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Hydrocarbon Development In The Beaufort Sea - Mackenzie Delta Region

ENVIRONMENTAL IMPACT STATEMENT
1982

VOLUME 2 DEVELOPMENT SYSTEMS

ENVIRONMENTAL IMPACT STATEMENT

FOR

HYDROCARBON DEVELOPMENT

IN THE

BEAUFORT SEA - MACKENZIE DELTA REGION

VOLUME 2
DEVELOPMENT SYSTEMS

1982

BEAUFORT SEA-MACKENZIE DELTA ENVIRONMENTAL IMPACT STATEMENT

**The Beaufort Sea Production Environmental Impact Statement
was prepared by
Dome Petroleum Limited,
Esso Resources Canada Limited
and
Gulf Canada Resources Inc.
on behalf of all land-holders in the
Beaufort Sea-Mackenzie Delta region.**

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ENVIRONMENTAL IMPACT STATEMENT

MASTER INDEX

TABLE OF CONTENTS

CHAPTER 4 BEAUFORT SEA-MACKENZIE DELTA DEVELOPMENT

CHAPTER 5 BEAUFORT SEA — MACKENZIE DELTA SUPPORT SYSTEMS

CHAPTER 6 OIL AND GAS TRANSPORTATION SYSTEMS

CHAPTER 7 CANADIAN BENEFITS

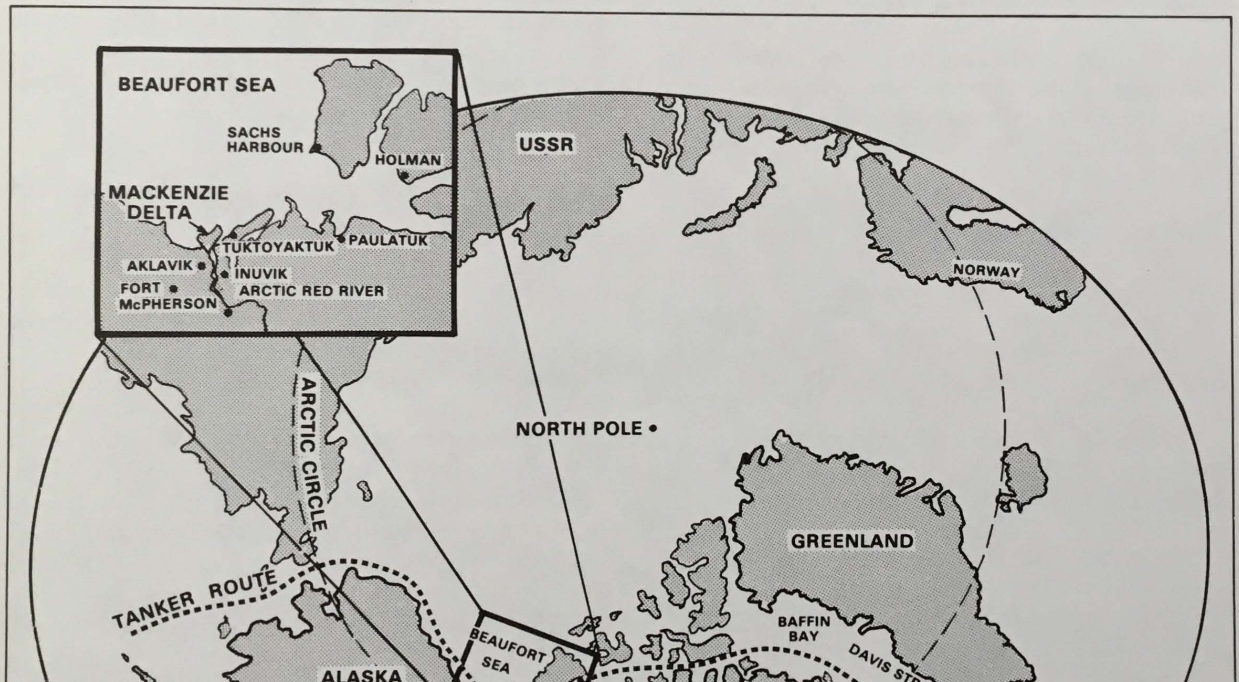
I. INTRODUCTION TO THE ENVIRONMENTAL IMPACT STATEMENT

THE PROJECT

Oil and gas exploration in the Beaufort Sea-Mackenzie Delta Region of Canada has been successfully undertaken during the past 17 years at an estimated cost of one billion dollars. Confirmation has now occurred of substantial gas reserves onshore and of major oil potential offshore. In order to meet Canada's energy needs, the next phase of hydrocarbon development in the Region is to provide oil and gas to southern markets.

Development of the Beaufort Sea - Mackenzie Delta Region involves making the hydrocarbon resources available to southern Canada over the next twenty or more years. This will involve continued exploration to delineate further and prove the existence of commercial reserves of oil, that is, reservoirs large enough to justify the expense of a transportation and production system.

Artificial islands, as support platforms for production facilities, will be built offshore where it is anticipated that most of the larger commercial oil reserves are located. Production systems will be installed both on islands and onshore and will be interconnected with gathering pipelines. These facilities will be of conventional design, being similar to many now in operation world-wide. Two transportation systems, namely tankers and pipelines, are being given serious consideration, and it is possible that eventually both will be employed for part or all of the transportation requirements. Support systems will also be established as required to service the production activities.



The Beaufort Sea-Mackenzie Delta Region, located in the western Canadian Arctic, has been the site of successful exploration drilling for approximately 17 years.

Services provided will include marine, air and land systems.

As occurred during the exploration phase of development, environmental and socio-economic considerations will go hand in hand with technical considerations throughout the years of hydrocarbon production.

THE PROPONENTS

The proponents are the companies who have exploration permits offshore in the Beaufort Sea or onshore in the Mackenzie Delta, or both. At this time there are about 50 companies holding permits in this region. The three principal proponents, however, are Dome Petroleum Limited, Esso Resources Canada Limited, and Gulf Canada Resources Inc. It is these three who have undertaken to prepare The Beaufort Sea-Mackenzie Delta Environmental Impact Statement (EIS).

SCOPE AND ORGANIZATION

This Environmental Impact Statement addresses the environmental and socio-economic issues associated with hydrocarbon production in the Beaufort Sea-Mackenzie Delta. The statement consists of the following volumes:

Volume 1 - Summary

Volume 2 - Development Systems

Volume 3A - Beaufort Sea - Mackenzie Delta Setting

Volume 3B - Northwest Passage Setting

Volume 3C - Mackenzie Valley Setting

Volume 4 - Biological and Physical Effects

Volume 5 - Socio-economic Effects

Volume 6 - Accidental Spills

Volume 7 - Research and Monitoring

Volume 1 is a condensed version of the entire Environmental Impact Statement and is intended to be used as an information document for the general public. In Volume 2, the Beaufort Sea-Mackenzie Delta development plan for the next twenty years is described. Included are a discussion of the energy needs of Canada, an identification of the level of production development required to achieve Canadian energy self-sufficiency, descriptions of engineering systems, support systems, Arctic tanker and overland pipeline transportation systems and a review of the Canadian benefits associated with development.

Volumes 3A, 3B and 3C provide physical and biological background information for the three major regions where production and transportation activities will occur. Volume 3A covers the Beaufort Sea-Mackenzie Delta production Region; Volume 3B, the Arctic tanker transportation corridors; and Volume 3C, the overland pipeline transportation corridor. Volume 4 deals with the possible physical and biological effects of the proposed development described in Volume 2, assuming that no major polluting accidents occur. Similarly, Volume 5 assesses the socio-economic effects of the proposed development. Volume 6 addresses the concern with accidental spills and other accidents, most of which have a low probability of occurring. Preventative measures, and those intended to mitigate the effects of such accidents are described. Finally, Volume 7 describes ongoing and future needs for research and monitoring based on the assessments carried out in Volumes 4, 5 and 6.

It should be recognized that the development plan may well be changed to take account of important socio-economic and environmental factors, as well as new technology. Site and project design details will be reviewed and reassessed at regular intervals throughout the 20 or more years of project development.

ENVIRONMENTAL ASSESSMENT REVIEW PROCEDURE

In July 1980, the issue of Beaufort Sea - Mackenzie Delta development was referred by the Department of Indian and Northern Affairs to the Department of Environment (Federal Environmental Assessment Review Office). An Environmental Assessment Panel was appointed to review all the diverse aspects of oil and gas production in the Beaufort Sea-Mackenzie Delta Region, including social, technical and environmental considerations. The Environmental Impact Statement and reports of detailed studies will be filed with the Environmental Assessment Panel as part of the Federal Environmental Assessment and Review Process.

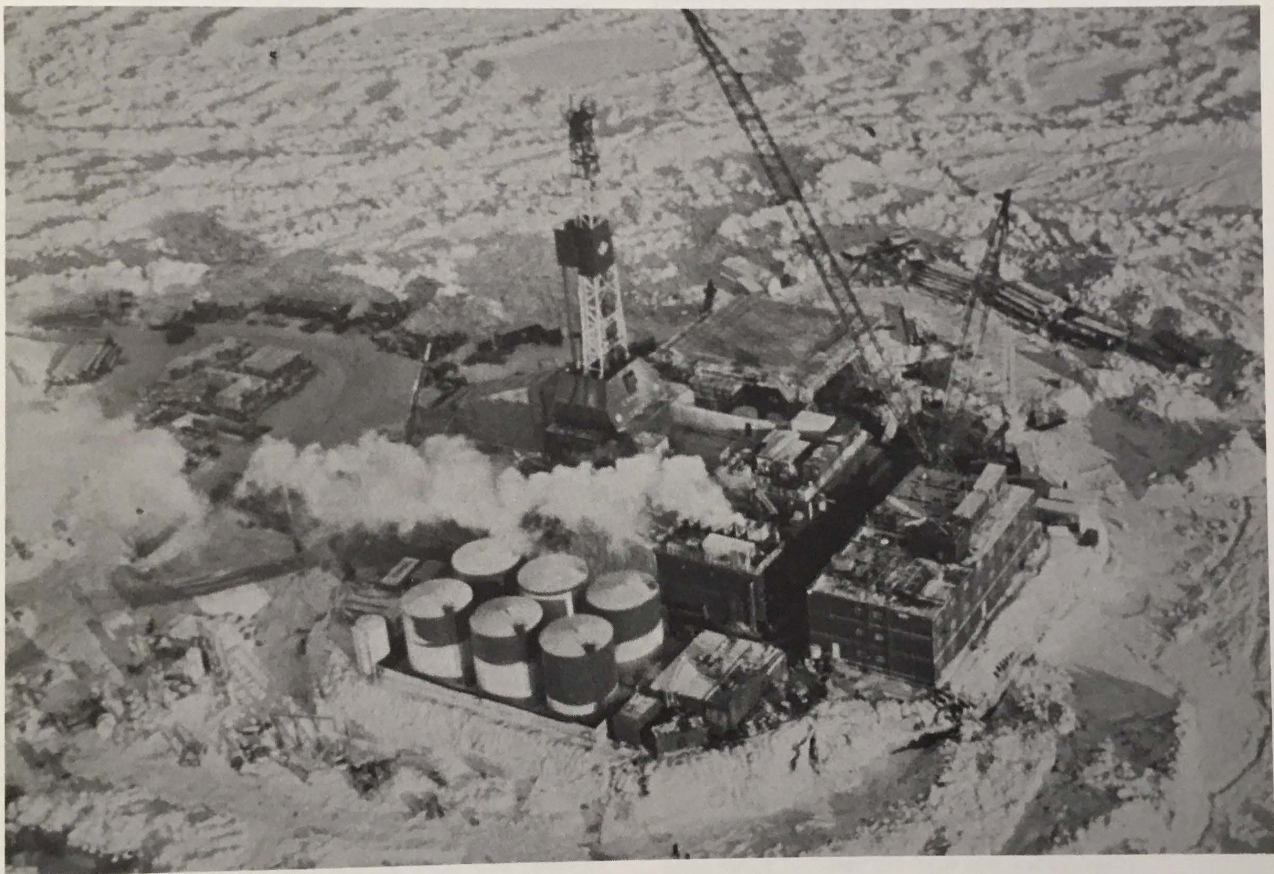
II INTRODUCTION TO VOLUME 2

Development of the potentially huge oil and gas reserves in the Beaufort Sea-Mackenzie Delta Region will involve a coordinated pool of manpower, equipment, materials and support services. This will require considerable advance planning to ensure that all logistical, technological and environmental concerns associated with development in this Arctic region of Canada are addressed. Volume 2, an inte-

gral component of the planning exercise, identifies and quantifies the separate components, activities and potential environmental disturbances associated with development in this region. This volume was prepared by the proponents with the assistance of Monenco Consultants Ltd.

The essential elements of this volume are: an explanation of the need for energy and a summary of the development plan to produce oil and gas over the next twenty years; a description of the proposed production and transportation systems and the construction activities required for their development, including specific details of the individual components of these systems and the construction and design modifications required to make them functional in an Arctic setting; and the expected Canadian benefits to be derived from this project.

This volume contains seven chapters as follows:



CHAPTER 1

THE NEED FOR ENERGY

The question as to whether or not Canada needs Arctic oil cannot be answered without first looking at the national energy policy and the future Canadian demand for and supply of energy.

The recent National Energy Program (NEP), in conjunction with Bill C-48 and the Federal-Provincial energy agreements, confirms the government's determination to pursue a policy of energy self-sufficiency for the nation. This policy has become an important factor, among others, in influencing Canada's energy supply and demand picture, both in the present and for the future.

Two recent studies on Canada's energy supply and demand, namely the 1981 National Energy Board report and the 1981 Canadian Energy Research Institute study, are used here as the basis of discussion. The former presents energy supply and demand forecasts for the period 1980 to 2000. The latter examines crude oil supply and demand in Canada, and addresses the major issues associated with various projected supply and demand scenarios for oil.

Neither of these studies is based on the latest pricing and taxation agreements reached between the Federal government and the producing provinces. For this reason they do not fully evaluate the impact on supply and demand balances and Canada's prospects for achieving self-sufficiency. There is a wide consensus among observers of the energy scene that to reach self-sufficiency it will be necessary to develop all the resources Canada has. Even if this happens expeditiously, Canada's economy faces a number of years during which the nation's import dependence will be increasing. It seems that the recent success in reducing oil consumption in Canada, even to the extent it can be considered a secular rather than cyclical trend, will not close the gap between liquid fuel demand and supply. To aim at closing this gap by the last decade of this century, action must be taken now, because to bring into production new resources in northern regions requires long lead times. The fiscal incentives made available to explorers, whether in the Arctic or off the East Coast, are tangible evidence of the fact that the government recognizes the need and value of developing viable alternatives now, in view of the long term objective.

1.1 THE NATIONAL ENERGY BOARD INQUIRY

The National Energy Board (NEB) inquiry into energy supply and demand in Canada observed that uncertainties in forecasting led to the adoption of the procedure of forecasting ranges of supply and demand rather than the single point forecasts previously used.

1.1.1 TOTAL ENERGY DEMAND

The forecasts are based on a combination of population growth, economic growth and stated energy price assumptions in Canada over the next two decades. The Board projected a population growth rate of 1% and an economic growth rate of 3.2% per year on the average for the next twenty years. These growth rates, combined with stated price assumptions, produce an estimated total energy demand in Canada equivalent to 730 thousand cubic metres per day of crude oil in 1980 increasing to 1.2 million cubic metres per day in the year 2000. This represents an increase of 2.3% per year over this period.

1.1.2 CRUDE OIL DEMAND AND SUPPLY

The National Energy Board (NEB) projected that the demand for crude oil in Canada would decline by 0.8% per year from 290 thousand cubic metres per day in 1981 to 270 thousand cubic metres per day in 1990 using the middle demand. The demand would then increase at a rate of 1.2% per year to total 302 thousand cubic metres per day by the year 2000. The ranges in the forecast pattern of crude oil demand are shown graphically in Figure 1.1-1.

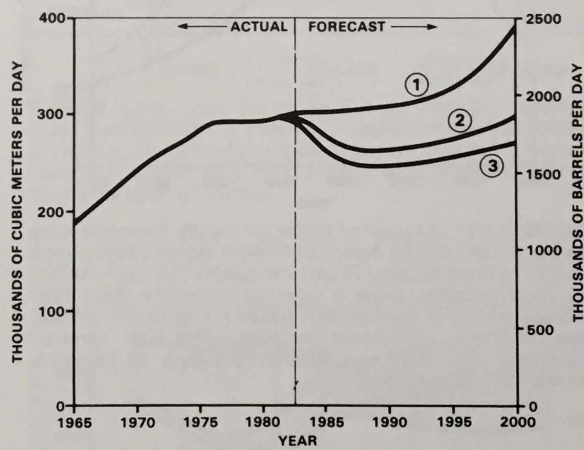


FIGURE 1.1-1 *The National Energy Board (1981) has made three projections of demand for crude oil in Canada up to the year 2000: high demand (1), middle demand (2), and low demand (3). The middle demand shows a small annual decrease to 1990 followed by a gradual increase to the year 2000. Demand is difficult to forecast as evidenced by the wide range between the high and low curves.*

Oil's share of total primary energy demand was projected to decline from 39% in 1980 to 29% in 1990 and further to 26% by the year 2000. Nonetheless, the NEB has forecasted that total oil consumption in 2000 will be 5% greater than in 1980.

The inevitable decline in oil production from the conventional producing areas of western Canada means that major new sources of supply will be required to meet Canadian demand. The NEB established a range of supply forecasts, as shown in Figure 1.1-2. The low (3) and base (2)supplies show a decline from the 1981 reserves of 230 thousand cubic metres per day. However, the high supply forecast (1), which includes optimistic increases in oil sands supply and enhanced oil recovery as well as new supplies from frontier regions, indicates a supply level of 380 thousand cubic metres per day in the year 2000. However, to get the balance of oil out of the existing fields will be increasingly costly, as productivity declines. In fact, the operating cost to withdraw the remaining oil in the existing wells has been rising faster than the general inflation rate. Furthermore, the projected increase in supply from oil sands plants will require six new plants at a cost of 90 to 120 billion dollars, which is a most unlikely prospect.

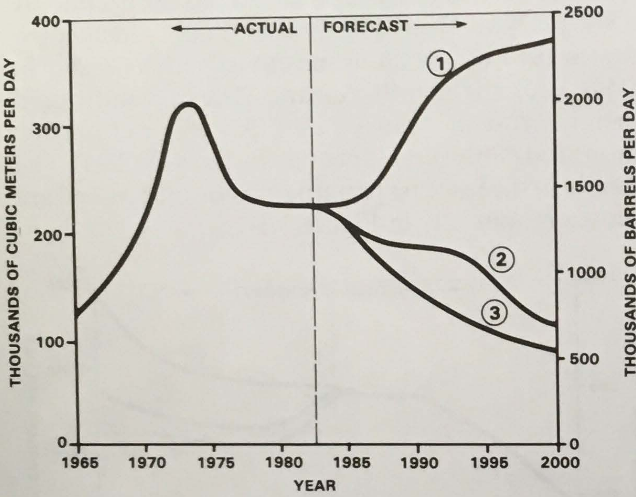


FIGURE 1.1-2 *A range of crude oil supply forecasts have been provided by the National Energy Board (1981): high supply (1), base supply (2) and low supply (3). Both the low and base supplies show a significant decline from 1981 reserves while the high supply, based on optimistic projections, shows a significant increase. The high forecast assumes a significant contribution to supply by oil sands and frontier discoveries.*

Assuming the more realistic middle demand and base supply forecasts, there will be a shortfall of 86 thousand cubic metres of oil per day in 1990, increasing to 177 thousand cubic metres per day in 2000. This is illustrated in Figure 1.1-3. The shortfall in supply will have to be met by additions to conventional reserves, oil sands plants, frontier development or imports. If these additions from Canadian sources are not made, a net increase of oil imports at a rate of 6% per year will be necessary.

1.1.3 NATURAL GAS DEMAND & SUPPLY

The NEB also examined the natural gas supply and demand outlook for Canada. The Board developed

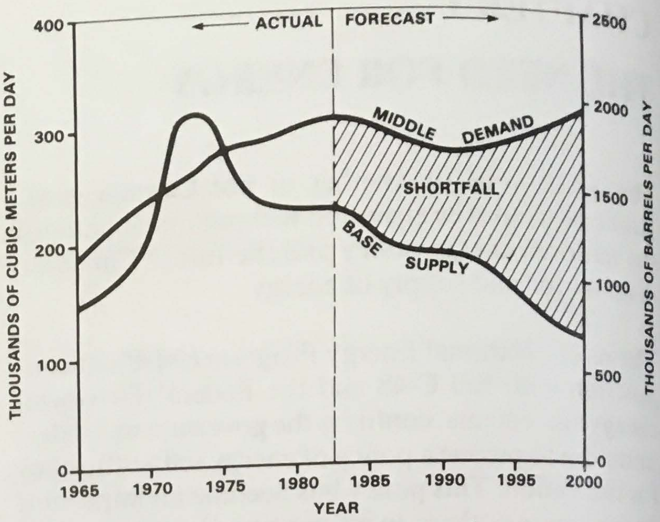


FIGURE 1.1-3 *Using the middle demand and base supply forecasts of the National Energy Board (1981), it is projected that there will be a supply shortfall of 86,000 cubic metres of crude oil per day in 1990. This will increase to 177,000 cubic metres per day by 2000.*

three cases of gas supply and demand to bracket its overall forecasts. Depending on the combination of supply and demand estimates considered, the Board found that gas demand would exceed supply from conventional producing areas as early as 1991 to as late as the year 2000. However, based on its middle case assessment of supply capability from present conventional producing areas and estimates of gas delivered from frontier areas, the Board concluded that no deficiency in supply would be encountered prior to 1998.

In their assessment the Board concluded that Canada had no further exportable surplus of natural gas beyond that which now occurs. However, the NEB is currently undertaking a three phase hearing into new gas export applications and, as a result of phase one, has recently revised its procedures for determining gas surpluses.

1.2 THE CANADIAN ENERGY RESEARCH INSTITUTE STUDY

The Canadian Energy Research Institute (CERI, 1981) study deals with the Canadian oil supply and demand outlook in a probabilistic manner using a low, base and high set of supply and demand assumptions, taking into account oil source, quality and transportation parameters.

CERI considered that over the forecast period to the year 2000, crude oil demand will moderate due to reductions in motor gasoline requirements and a shrinking market for fuel oils due to the increasing use of natural gas. Using base case demand assumptions, the Institute estimated that total Canadian demand for crude oil will be 302.5 thousand cubic metres per day in 1985 increasing to 310 thousand

cubic metres per day in 2000. The high demand estimates are considerable, up to 380 thousand cubic metres per day by the year 2000.

On the supply side, the institute concluded that conventional crude oil supplies will decline to provide only one quarter of the total crude oil supply by the year 2000. In contrast, synthetic and frontier oil, which presently supply only a minor proportion, will increase to nearly 60% of the total domestic supply. The base case oil supply developed by CERI represents a total domestic supply of 211 thousand cubic metres per day in 1985 increasing to 285 thousand cubic metres per day by 2000. Of the total supply in the year 2000, only 65 thousand cubic metres per day will be supplied from established reserves. New discoveries and tertiary recovery, oil sands and frontier development are projected to supply 80, 90 and 50 thousand cubic metres per day respectively.

In comparing base case supply with base case demand, the CERI study concluded that in 2000 a remaining balance of 25 thousand cubic metres per day would have to be met by imports. However, the high case developed in the CERI study demonstrates that Canada could be self-sufficient in oil supplies by the year 2000. The probablity of self-sufficiency will increase from 0 in 1985 to 0.54 in the year 2000. The probability of large-scale foreign dependence will fall from 0.22 in 1985 to 0.06 in the year 2000. The Federal Government's goal of self-sufficiency by 1990 will not likely be achieved unless there is a very substantial departure from anticipated crude oil supply and demand patterns.

The CERI study examined five major crude oil supply sources and determined the relative attractiveness of the sources by evaluating the security from supply interruption, the longevity of supply capability, the quality of the supply as a refinery feedstock, the transportability of the supply to refineries and the relative economics. Figure 1.1-4 summarizes this evaluation in matrix form and ranks the relative attractiveness of the five supply sources. Synthetic and frontier oil will be the most attractive oil supply sources for the future as technical hurdles are overcome.

1.3 THE ADVANTAGES OF PROCEEDING WITH DEVELOPMENT OF THE BEAUFORT-MACKENZIE DELTA REGION

The crude oil supply shortfall, as shown in Figure 1.1-3, can be reduced or eliminated by the construction of oil sands plants and the development of East Coast and Beaufort Sea - Mackenzie Delta resources. The oil sands plant construction schedule projected in the high supply case by the NEB, which would increase total oil sands production to 165 thousand cubic metres per day in 2000, is improbable; in fact, it is likely that additional oil sands production in 1990 and 2000 will be 24 and 56 thousand cubic metres per day, respectively. East Coast production may reach 32 thousand cubic metres per day by 1990 and 48 thousand cubic metres per day by 2000. The remaining shortfall, as shown in Figure 1.1-5, will be 56 thousand cubic metres per day in 1990 and 95 thousand cubic metres per day in 2000. This shortfall can be met by development in the Beaufort Sea - Mackenzie Delta Region. Current events, such as postponement of tar sands projects and probable delays in development of East Coast resources, affirms the need for Beaufort Sea development.

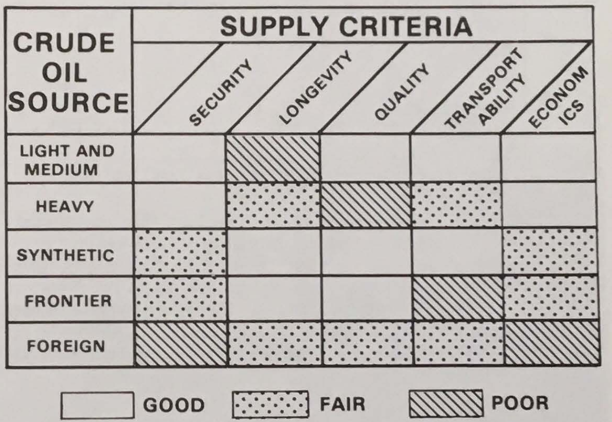


FIGURE 1.1-4 *The Canadian Energy Research Institute (1981) established a matrix to demonstrate the relative attractiveness of the five crude oil supply sources. This indicates that frontier oil is most attractive for its quality and the long time span of supply.*

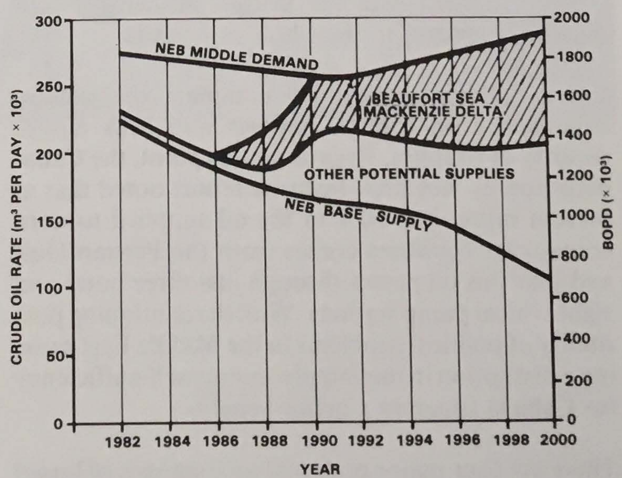


FIGURE 1.1-5 *The crude oil supply shortfall could be reduced by development of other potential supplies such as oil sands and the East Coast offshore. The remaining shortfall in supply could be met from Beaufort Sea-Mackenzie Delta reserves.*

The possible rate of development of hydrocarbon resources in the Beaufort Sea-Mackenzie Delta Region is described in detail in Chapter 3, Development Plan. Figure 1.1-6 demonstrates the range of production possible from the Beaufort Sea -Mackenzie Delta Region. If the intermediate development rate shown in the figure is reached, it is clear that crude oil self-sufficiency can be achieved by 1990.

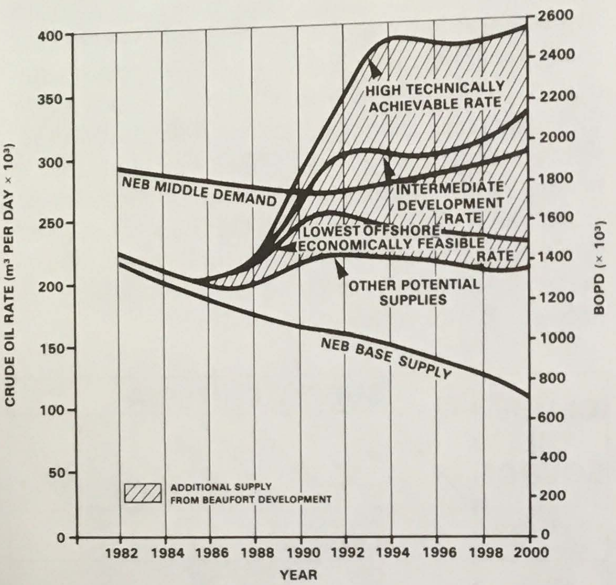


FIGURE 1.1-6 *Development of Beaufort Sea-Mackenzie Delta oil reserves will make it possible to achieve oil self-sufficiency for Canada by 1990. The shaded area indicates oil that could be supplied from this region for three different development rates (see Chapter 3). The difference between the various rates projected for the Beaufort is attributed to the pace of development as opposed to the expectations for success.*

While the costs of developing hydrocarbon resources in the Beaufort Sea - Mackenzie Delta are high, the benefits are also considerable. The most direct benefit is energy self-sufficiency for Canada. However, development will also add to the range of choice in meeting energy needs, will help meet other government objectives and will bring considerable economic advantages to the whole of Canada.

Energy self-sufficiency will eliminate the present dependence on foreign imports and thus ensure security of supplies. Regarding this point, the Canadian Energy Research Institute report noted that at present more than 60% of the oil supplied to non-communist countries comes from the Persian Gulf and that this oil passes through just three ports and eight critical pump stations. With the continuing possibility of political problems in the Middle East causing a disruption in this supply, energy self-sufficiency for Canada becomes a major benefit.

There are four major potential new sources of liquid fuel in Canada which may add to existing supplies: the Arctic, East Coast offshore, oil sands and enhanced recovery. Which sources will be developed and in what order will be determined by the outcome of exploration activity, government policy and economic feasibility. However, it is likely that most, or all, of these new energy supplies will be needed at some stage. Thus development of the Beaufort Sea-Mackenzie Delta Region will provide one option for meeting Canadian energy needs.

Development of this resource is also consistent with government policies to encourage development of natural resources, to increase industrial development, to develop new Canadian technology and to provide industrial training and employment to areas with lower levels of industrial development. Some of the projected benefits of Beaufort Sea - Mackenzie Delta development are mentioned here but are examined in more detail in Chapter 8.

The major indirect economic advantages of developing the Beaufort Sea - Mackenzie Delta Region are economic growth, provision of employment opportunities, regional benefits and increased government revenue. Ultimately about 85% of the goods and services required could be provided from Canadian sources. Thus this development will contribute to an increase in the Canadian Gross National Product and will also supply revenue to the government in the form of royalties and taxes. Using projections from the Beaufort Planning Model (described in Chapter 3), it is estimated that up to 240,000 jobs could be created by 2000 through direct and indirect employment. This level of activity would bring about a reduction in the unemployment rate in Canada. Since all economic forecasts predict an underutilized economy and high unemployment rates, development of this nature would boost the Canadian economy without displacing investment from other sources. Finally, these economic benefits would accrue to most regions of the country.

1.4 CONCLUSIONS

Both the NEB inquiry report and the CERI study identify the need for large volumes of additional oil supply to meet Canadian needs, even under the lowest plausible Canadian oil demand scenario. The development of frontier resources in the Beaufort Sea - Mackenzie Delta Region and off the East Coast of Canada, and development of oil sands plants are required to meet this demand. Furthermore, development of these resources could achieve self-sufficiency in crude oil for Canada.

The Beaufort Sea-Mackenzie Delta Region has potential oil reserves of 0.9 to 5.1 billion cubic metres (6 to 32 billion barrels) (Canada Energy, Mines and Resources, 1976). In comparison, the North Sea was assessed in 1980 as having between 1.6 and 1.92

billion cubic metres (10 to 12 billion barrels) of oil in a developed, recoverable form.

Not only will development of the Beaufort Sea - Mackenzie Delta hydrocarbon resources help meet future Canadian energy demands, but it will also generate much economic activity throughout Canada.

1.5 REFERENCES

Canada Energy, Mines and Resources. 1976. Oil and Natural Gas Resources of Canada. EP77-1.

Canadian Energy Research Institute. July 1981. Crude Oil Supply and Demand: Major Issues and Alternate Scenarios. Working Paper 81-1.

Dome Petroleum. 1982. Beaufort Planning Model

National Energy Board. June 1981. Canadian Energy Supply and Demand 1980-2000.

CHAPTER 2
HYDROCARBON POTENTIAL AND EXPLORATION HISTORY

2.1 HYDROCARBON POTENTIAL

The Beaufort Sea-Mackenzie Delta Region of Canada, stretching from Amundsen Gulf in the east to the Canada-Alaska border in the west, and its offshore continental shelf, has all the attributes of a major hydrocarbon producing area. The Tertiary age sediments underlying this large geographic region are similar to Cretaceous and Tertiary age sediments in other parts of the world that have yielded the majority of the world's oil and gas supplies. Exploration activity in the Beaufort Sea-Mackenzie Delta Region has revealed significant oil and gas accumulations, and has demonstrated the region's potential for large-scale energy production.

2.1.1 BASIN GEOLOGY

The Beaufort Sea-Mackenzie Delta sedimentary basin is bounded by the folded Cordillerian Region on the southwest, the stable platform of the Canadian Shield and Interior Plain on the southeast, and the Canada Basin to the north. This roughly triangular basin, as shown in Figure 2.1-1, has an area of about 420,000 square kilometres. The area presently being explored covers about 100,000 square kilometres. Thick wedges of Tertiary sediments (up to 10 kilometres thick) in the basin are the target of exploration activity.

Sedimentation in the basin dates from the Triassic time (starting roughly 200 million years ago) and takes place today much as it did then, along the active portions of the Mackenzie Delta. Figure 2.1-2 is a cross-sectional profile of the stratigraphy of the basin along a northwest to southeast line. The sediments of this basin are marine in origin, and are predominantly materials derived from the erosion of adjacent areas in what has been called the Interior Platform (Lerand, 1973; Young *et al.*, 1976, Horn and Mroszczak, 1980).

The present Beaufort Sea-Mackenzie Delta Basin

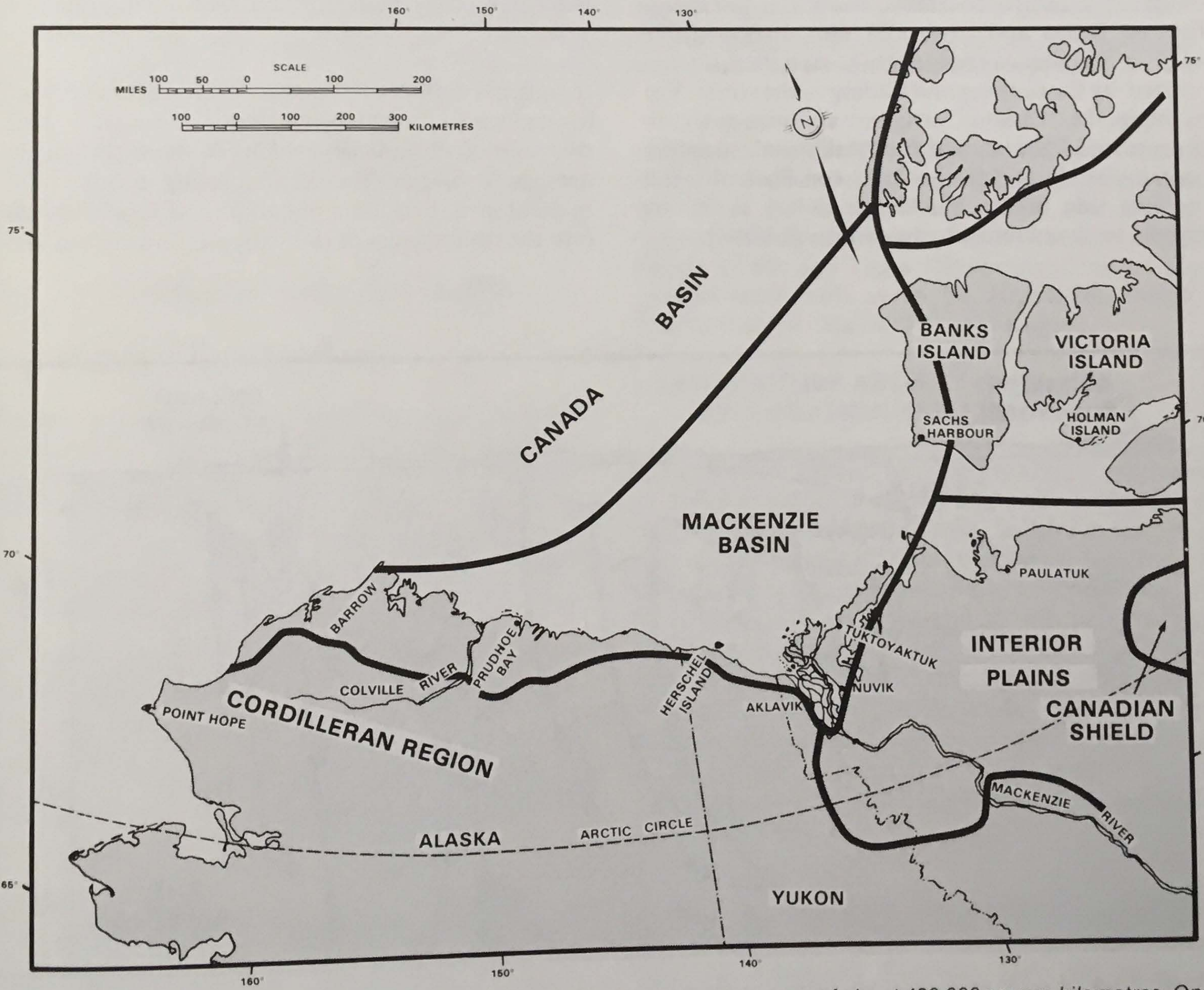


FIGURE 2.1-1 *The Beaufort Sea-Mackenzie Delta sedimentary basin has an area of about 420,000 square kilometres. Only about 25% of the basin is presently being explored.*

extends onshore in the vicinity of the Mackenzie Delta and Tuktoyaktuk Peninsula, as well as the Yukon Coastal Plain. The Coastal plain sequence is relatively well exposed and includes marine and fluvial shales and sandstones. Offshore, the basin is estimated by geologists to be at least eight kilometres thick with the sedimentation of three ancient periods: the Upper Cretaceous era (about 100 million years ago), the more recent Paleocene era (70 million years ago), and the still more recent Neocene phase (25 million years ago). It is this eight kilometre thick vertical section which has the most promising oil bearing structural traps within it.

As shown in Figure 2.1-3, the Beaufort Sea-Mackenzie Delta Basin has three structural zones. Zone I forms the southern and eastern rims of the basin and has normal faults composed of Paleozoic era (550 to 200 million years ago), and Mesozoic era (200 to 70 million years ago) rocks.

The stratigraphic units of the Mackenzie Delta-Tuktoyaktuk Peninsula region within Zone I show the promise of hydrocarbons. In an area parallel to Eskimo Lakes and Liverpool Bay, hydrocarbons have been discovered within structural traps created by the faulting and folding of the strata. For example, the "Parsons" structure contains gas, condensate and light oil, and the "Atkinson" structure contains oil. However, the Anderson Plain area (on the east side of the Mackenzie Delta), is felt by experts to have limited hydrocarbon potential.

The nearshore Beaufort Sea area (Zone II) around Richards Island and the Delta is underlain by many structural and stratigraphic traps in porous sand bodies. The Taglu Field within this area has hydrocarbons trapped in thick, cyclical sediments which range from non-porous rocks upwards to the porous sandstone above.

Zone III, further out in the Beaufort Sea, has mobile shale structures, which have formed into wave-like or dome-like structures under the surface of the ocean floor. These structures, which are estimated to be quite large, were caused by the swelling up of loosely compacted shale in a period as far back as 160 million years ago. This swelling of shale, which tends to flow under greater pressure, has deformed the overlying strata and resulted in substantial hydrocarbons being trapped, a fact attested to by the oil discoveries in structures such as Nektoralik and Kopanoar.

Geologists have conducted studies of the well cuttings from the northern offshore Beaufort area, and have determined that the principal oil reservoirs are Paleocene in age, being formed about 50 to 60 million years ago.

It appears that there was once an ancestral river located where the Mackenzie River flows today. This river entrenched a valley which eventually became a deep canyon under the ocean, cutting into the continental shelf. Erosional material was funneled down into the deep waters of this canyon, flowing out in a

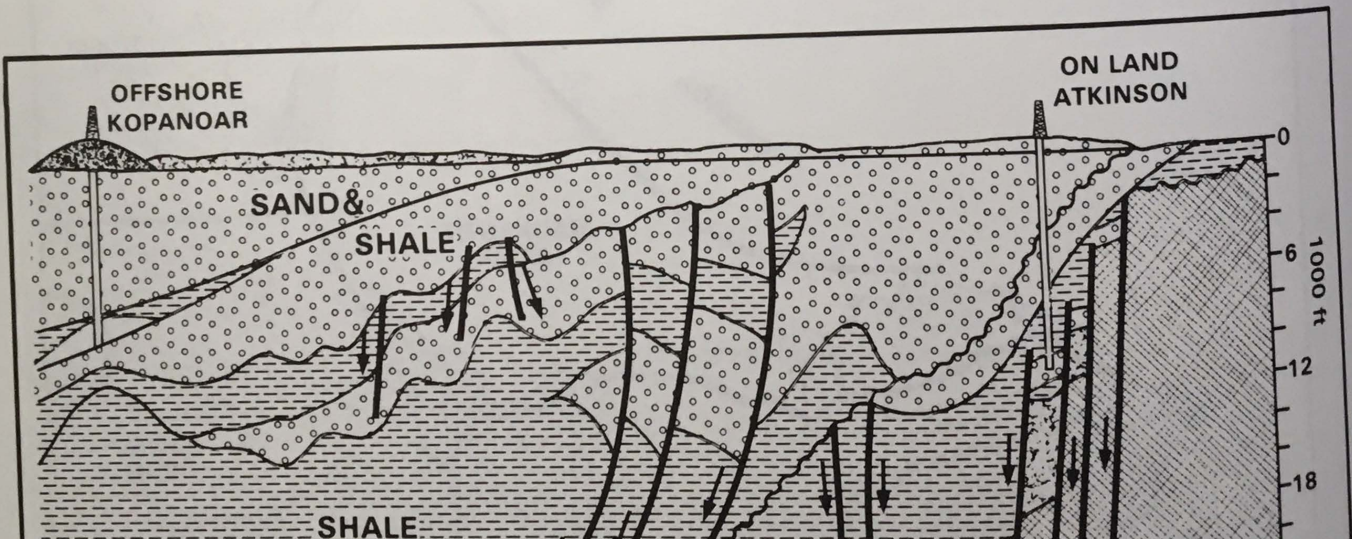


FIGURE 2.1-2 *A north to south cross-section of the Beaufort Sea-Mackenzie Delta sedimentary basin illustrates the thick section of rock which is suitable for the generation and trapping of hydrocarbons. Exploration drilling has demonstrated that the onshore and nearshore areas tend to be gas prone while the sediments below the deeper water are oil prone. The basin has characteristics very similar to other existing producing oil basins in the world.*

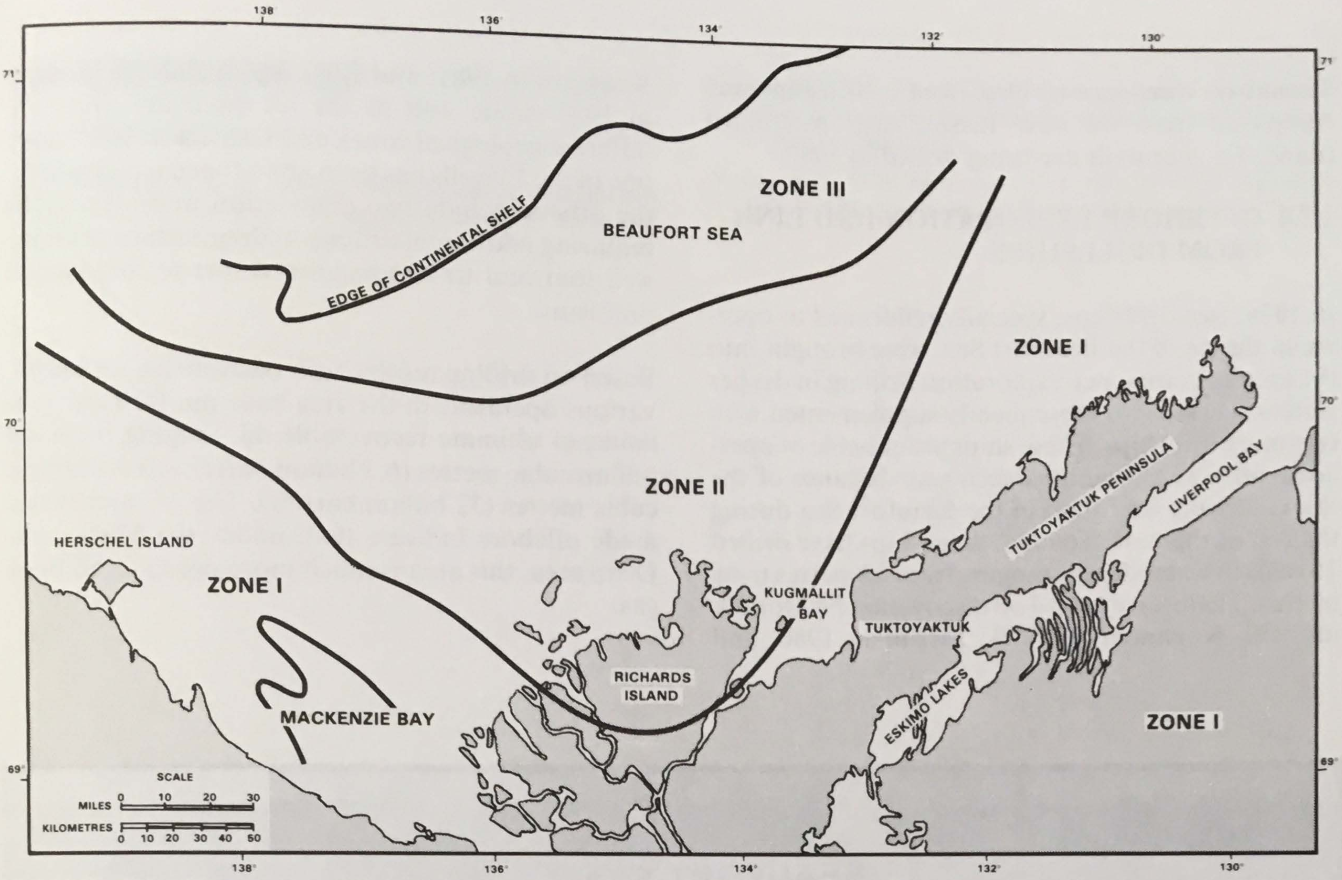


FIGURE 2.1-3 *Three distinct structural zones exist in the Mackenzie Delta Basin. The significant oil discoveries made to date are in Zone II, where exploratory drilling has demonstrated that the seismic interpretations of sub-surface structure are very accurate and the structures are relatively simple and predictable.*

fan shape at the base of the continental slope. It is these deep-sea sands that contain oil in structures such as Kopanoar.

2.2 EXPLORATION HISTORY

2.2.1 SEISMIC EXPLORATION

The initial stage of petroleum industry activity in the Beaufort Sea-Mackenzie Delta area consisted of the gathering of seismic data. This began in the early 1960's onshore in the Delta. Throughout the 1970's seismic data acquisition also took place offshore, and is presently continuing in areas where operators anticipate finding major hydrocarbon accumulations.

To date, operators have obtained about 100,000 kilometres of seismic data, both onshore and offshore. These data in turn have led to the discovery of many subsurface structural anomalies which warranted further exploration by drilling. In the offshore area alone, more than 90 potential hydrocarbon-bearing structures have been identified.

2.2.2 ONSHORE EXPLORATION DRILLING

The first onshore well, BA-Shell-Imperial Reindeer, was drilled on Richards Island in 1965. Since then, various operators have drilled about 100 wells onshore in the Mackenzie Delta (Figure 2.2-1). Oil discoveries were made at Atkinson Point in 1970, and at Mayogiak in 1971. Two major gas fields were discovered - Parson's Lake and Taglu. Other oil and/or gas discoveries were made at Ya Ya, Niglintgak, Imnak, Titalik, Kumak, Mallik, Ivik and Kugpik.

2.2.3 OFFSHORE ARTIFICIAL ISLAND EXPLORATION DRILLING

Possible hydrocarbon bearing geological structures identified offshore prompted the drilling of the first offshore well in the Beaufort Sea in 1973 at Immerk. This well was drilled from an artificial island constructed in 3 metres of water. Since then, island building technology has advanced to the point where islands in water depths up to 65 metres are now feasible. To date, 21 artificial islands have been constructed, in water up to 22 metres deep. Twenty-three wells have been drilled from these islands, resulting in oil discoveries at Adgo in 1973, Garry in 1976, and Issungnak in 1980; and gas discoveries at Netserk in 1976, and Isserk in 1978.

Three of the island wells were delineation wells on the Adgo discovery, one was a directional well to delineate the Issungnak discovery. Over the winter of 1981-82, a successful delineation well to the original

Tarsiut oil discovery (drilled from a drillship) was completed from the new Tarsiut caisson-retained island. Further wells are being drilled in 1982.

2.2.4 OFFSHORE EXPLORATION DRILLING FROM DRILLSHIPS

In 1976, two drillships, specially reinforced to operate in the ice of the Beaufort Sea, were brought into the area to commence exploration drilling in deeper waters. These were subsequently supplemented with two more drillships. These ships are capable of operating only 3 to 5 months each year because of the thick, moving ice found in the Beaufort Sea during the rest of the year. To date, these ships have drilled 15 wells in water depths ranging from 23 metres to 68 metres. There have been 4 oil discoveries: Nektoralik in 1977, Kopanoar in 1979, Tarsiut in 1980, and Koakoak in 1981; and 2 gas discoveries: Nektoralik in 1977 (same well as the oil discovery, but in a different geological zone), and Ukalerk in 1977. Only one of the 15 wells has been abandoned as a dry hole; the others include two delineation wells, five wells requiring additional drilling and/or testing, and one well that had to be abandoned due to mechanical problems.

Based on drilling results both onshore and offshore, various operators in the area have put forward estimates of ultimate recoverable oil, ranging from 0.9 billion cubic metres (6.3 billion barrels) to 5.1 billion cubic metres (32 billion barrels). The oil discoveries made offshore indicate that, unlike the Mackenzie Delta area, this area is much more prone to oil than gas.

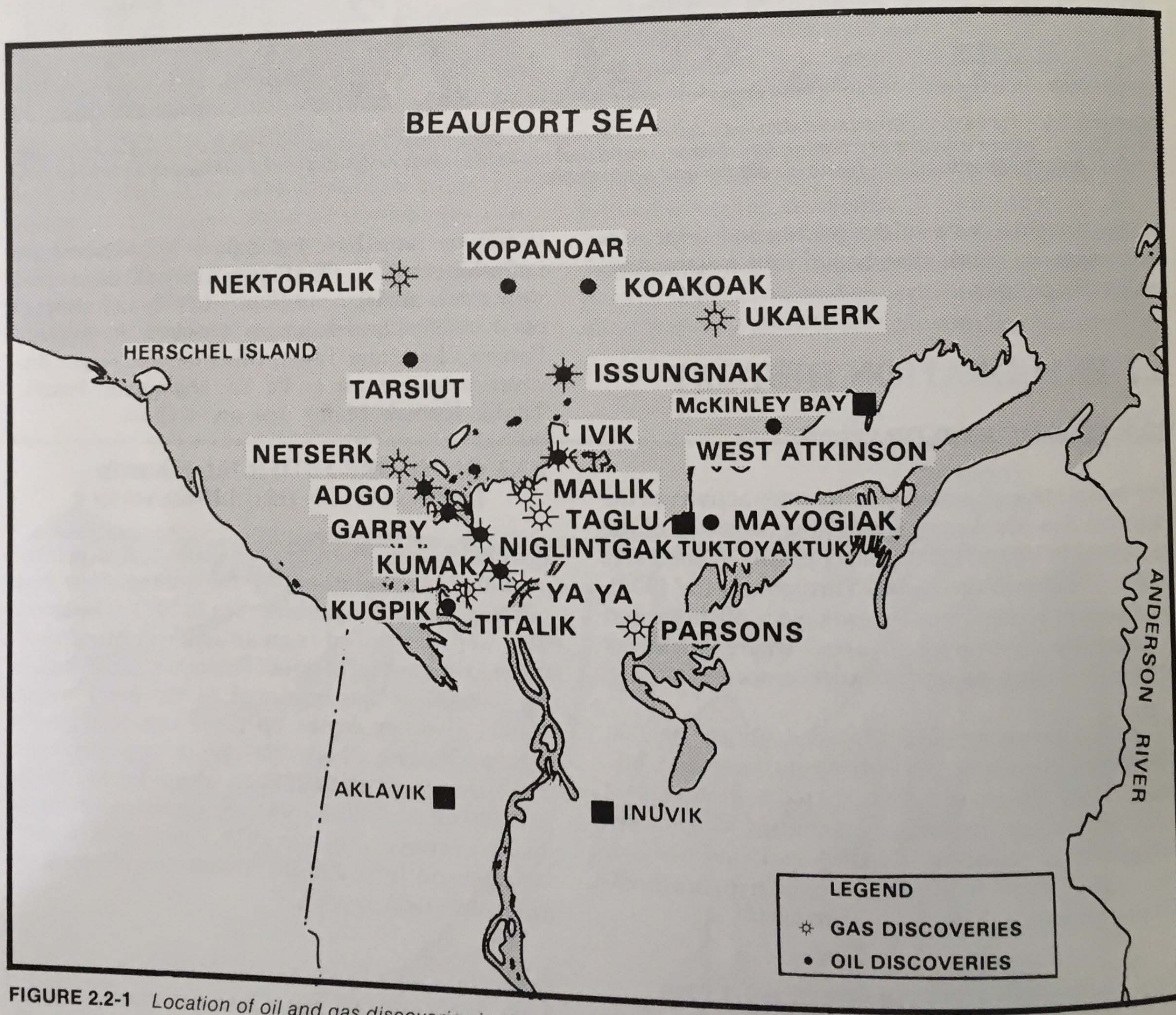


FIGURE 2.2-1 *Location of oil and gas discoveries in the Mackenzie Delta and Beaufort Sea.*

2.3 REFERENCES

2.3 REFERENCES

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CHAPTER 3 - DEVELOPMENT PLAN

This chapter describes the short-term and long-term development plan, followed by a discussion of the various development options and factors which influence the development plan. The chapter concludes with a presentation of projected levels of activity in the Region for the range of production rates.

As discussed in Chapter 1, it is considered necessary to develop the energy resources of the Beaufort Sea-Mackenzie Delta Region. In this chapter it will be demonstrated that to achieve energy self-sufficiency by the early 1990's, it is essential to proceed with development promptly. The development plan presented is designed to be both technically achievable and economically viable, while responding to environmental and social concerns.

3.1 THE DEVELOPMENT OBJECTIVE

Declining oil production from conventional sources, combined with a slight growth in demand, are projected to result in an oil shortfall in Canada of 86 thousand cubic metres per day by 1990 (575 thousand barrels) and as much as 177 thousand cubic metres per day by the year 2000 (1.2 million barrels). The current industry estimates of the ultimate oil potential of the Beaufort Sea-Mackenzie Delta Region range from 0.9 to 5.1 billion cubic metres (6 to 32 billion barrels).

This development presents an opportunity to help Canadians achieve three major goals: attainment of oil self-sufficiency by the 1990's, creation of new employment opportunities and regional development. Oil self-sufficiency is important to Canada, not only

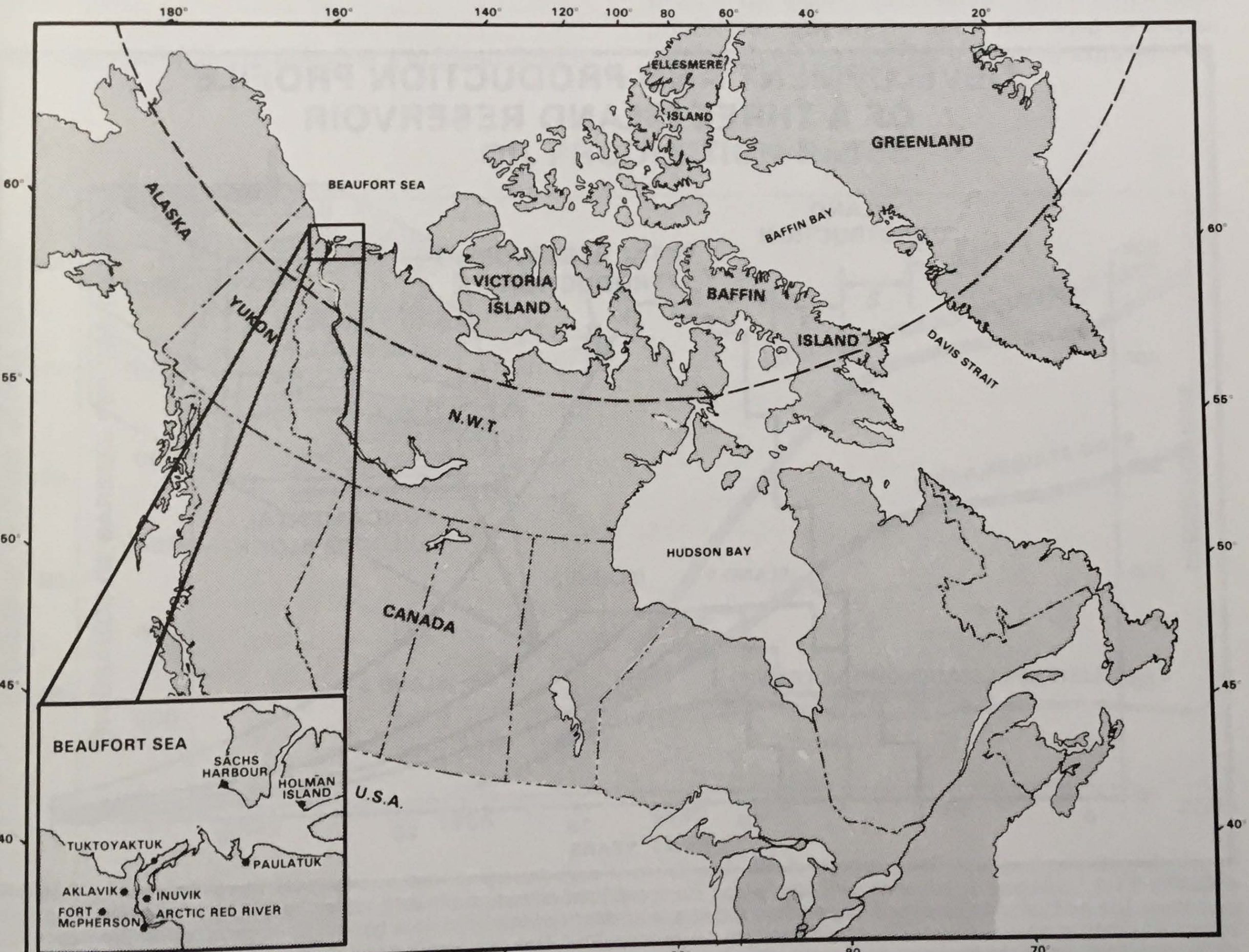


FIGURE 3-1 *It is proposed to develop the oil and gas reserves of the Mackenzie River Delta and southeastern Beaufort Sea in the western Canadian Arctic. The area is about 500 miles east of the giant Prudhoe Bay field which has been in production for several years. Because of its proximity to the North Pole the area is approximately equal distance from Japan, Northern Europe and the East and West Coast of North America.*

because it establishes security of supply and provides greater stimulation to the economy.

However, all potential sources of new oil require time to be brought into production. Assuming the first commercial oil field is confirmed in 1982, first production from the Beaufort Sea could occur by 1986, provided planning, design and implementation begin now. Extensive operational experience during the past two decades has developed both the knowledge and technology to make production and transportation systems for oil both technically and economically feasible.

Offshore development activity is composed of several fundamental parts. They include island construction, the drilling and completion of production wells, the installation of production and processing facilities, and the establishment of a transportation system. Once all of these components are in place the Region can be brought into production and the hydrocarbons transported to market.

The rate at which these reservoirs are discovered is the major factor which determines the rate of development. However, this rate of development is also influenced by external factors such as the market demand for oil.

Figure 3.1-1 illustrates how production increases in a step-wise fashion as development wells are drilled from an artificial island and placed on production. Note that this requires production and drilling operations to take place simultaneously. The peak production rate is reached after all the wells have been drilled. This rate is typically maintained for several years and then it commences to decline as the reservoir energy is depleted. It is important to note that this production profile is based on the reserves accessible from a given artificial island location rather than from the total reservoir. Thus, if the reservoir was larger than the area accessible from one island, one or more satellite islands would be built and the total reservoir production profile would be the sum of production from several islands as also shown in Figure 3.1-1.

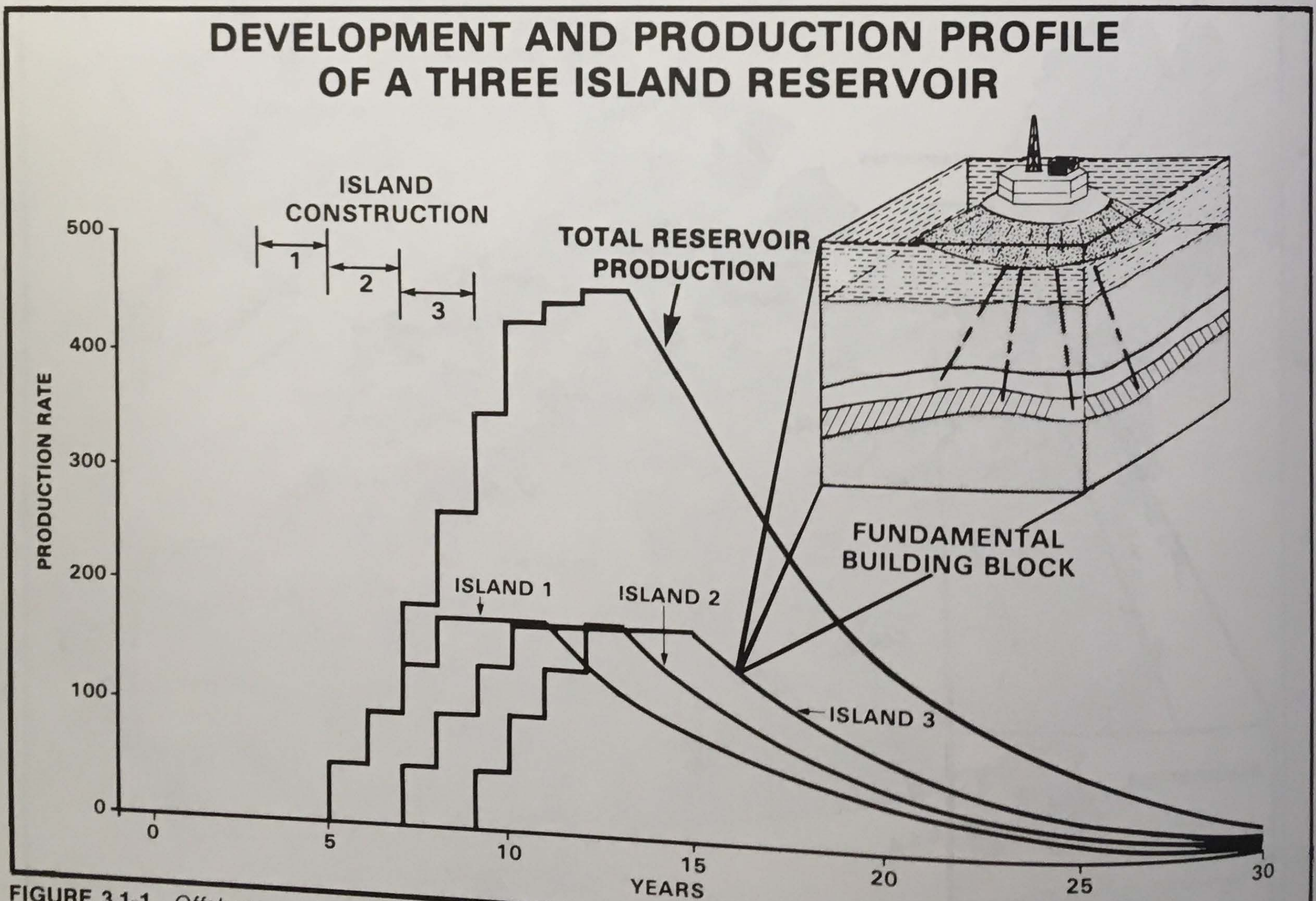


FIGURE 3.1-1 *Offshore production will take place from artificial islands built with sand, capped with concrete or steel caissons. The number of islands will depend on the size and depth of the field. In a typical field, production increases in a step-wise fashion as wells are drilled and brought on production. The maximum production rate that a field achieves is determined principally by the production capacity of the individual wells. An island, along with the wells drilled from it, and the production facilities to process the oil may be regarded as a building block. Each building block is more or less an economic unit.*

The shape of the production profile in Figure 3.1-1 is determined by many factors including the reservoir characteristics, the productivity of the wells, reservoir management and field economics.

In the second phase of oil field development, further reservoirs are systematically discovered and placed on production in the most efficient manner to achieve a continuing oil supply. These one island systems are then assembled one after the other to sustain production. They may also be assembled simultaneously to increase the rate of production, as illustrated in Figure 3.1-2. Thus the production profiles shown in Figure 3.1-2 represent an addition of the production profiles of all of the reservoirs that are brought on production in the region over the forecast period.

A range of oil production profiles, each representing its own development plan is also shown in Figure 3.1-2. Due to the large number of variables (technical, environmental, economic and regulatory) that have an impact on development, the most practical way to discuss Beaufort Sea-Mackenzie Delta production is to display a range of achievable development rates.

The high rate of production shown in Figure 3.1-2 is considered technically feasible based upon current knowledge of the region. Logistics, government approvals, economics and the availability of markets and capital are not considered in developing this high rate of production. Therefore, it is certain that many constraints will emerge which will prevent this level of production from being achieved.

The lowest production case presented is based on lower oil reserve assumptions and, therefore, a slower pace of development. The slower pace of development could also be a result of slower discoveries of new reserves, environmental issues, legal and governmental concerns, financial and/or logistics constraints or operational problems such as recurrent abnormal sea ice conditions. These constraints are discussed in more detail. The low case also represents the lowest economically feasible production rate for development in the deeper waters of the Beaufort Sea.

A complete array of oil production profiles exists between the low case and the high case. One of these is the intermediate production rate shown in Figure 3.1-2. This represents a more likely rate of development in the region. The assumptions on which these production rates are based are discussed in Section 3.2.1. It should be noted that the production profiles

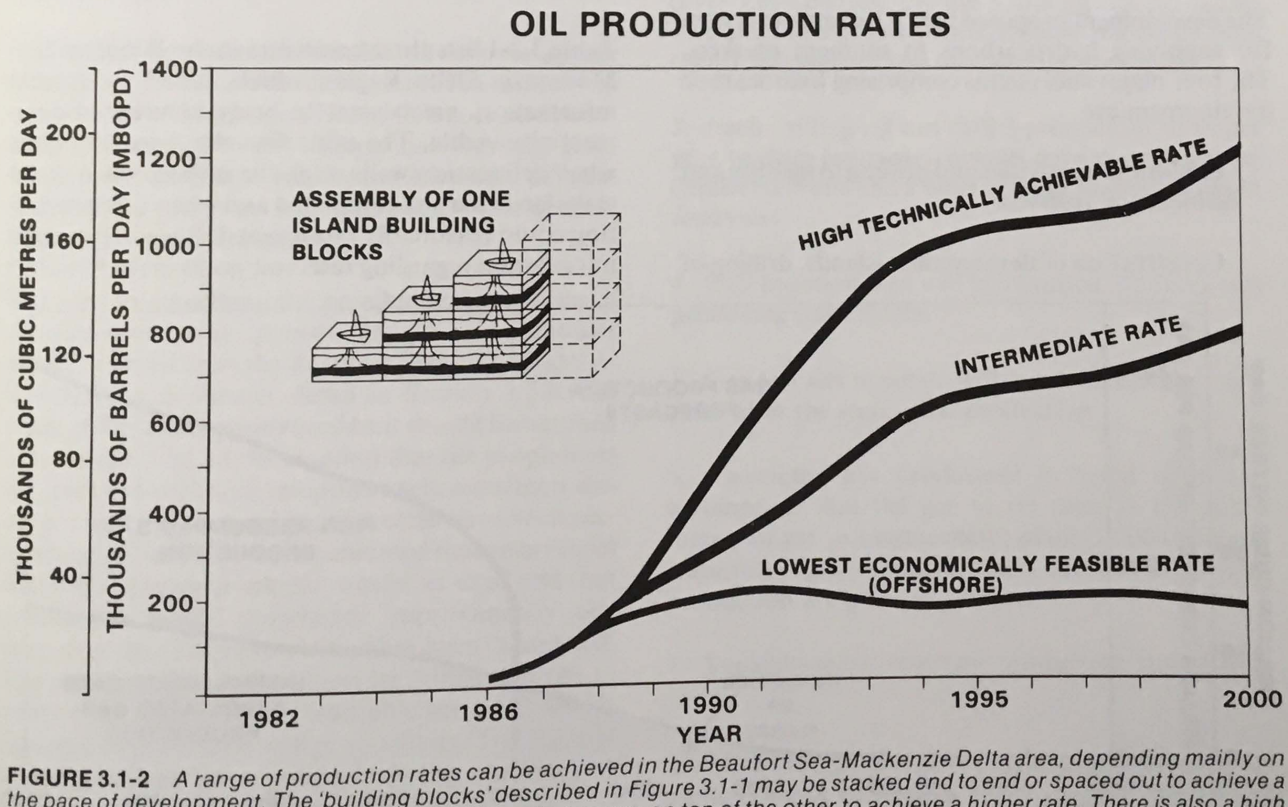


FIGURE 3.1-2 *A range of production rates can be achieved in the Beaufort Sea-Mackenzie Delta area, depending mainly on the pace of development. The 'building blocks' described in Figure 3.1-1 may be stacked end to end or spaced out to achieve a slower growth of production or placed closer together or one on top of the other to achieve a higher rate. There is also a high rate which is determined by such things as the availability of resources required to develop the various fields. It can be demonstrated that the high rate is an environmentally acceptable scheme. The intermediate production rate for the Beaufort Sea-Mackenzie Delta area lies between the two. This curve illustrates the production rate in 1990 of approximately 300,000 barrels per day, increasing to about 700,000 barrels per day by the year 2000.*

would be generally similar for the tanker or pipeline oil transportation alternatives. The distinctions between these are discussed later.

Gas production forecasts for the intermediate production rate are shown in Figure 3.1-3. Gas production rates are largely dependent on oil production rates since a large portion of the gas is associated with oil. Both associated gas and unassociated gas from gas fields will be sold when markets and transportation systems are developed.

3.2 THE DEVELOPMENT PLANNING PROCESS

Major project planning has become a sophisticated science. Large projects dictate the need to take into account thousands of events and factors that interrelate to bring the project on line. This type of planning is always preceded by the development of detailed lists of project planning constraints and assumptions. Computers have provided the capability to handle these large volumes of data and thus to assess the large number of variables and the interrelationships between them.

3.2.1 GENERAL ASSUMPTIONS

The development proposed here is a complete system for supplying hydrocarbons to southern markets. The four major subsystems comprising hydrocarbon development are:

- Exploration activities and drilling to identify and delineate oil reserves;

- Construction of development islands, drilling of wells and assembly of oil production facilities;

- Gathering of oil through subsea pipelines or onshore gathering systems to the production and transportation facilities;

- Transportation of hydrocarbons to southern markets by marine vessels, through an overland pipeline, or some combination of both.

All these subsystems must be in place before hydrocarbons can be recovered and transported to market.

Each of the proposed transportation systems, tankers and pipelines, is unique in almost all aspects; only the function of the systems is the same. Therefore, in the development plan proposed here, it is assumed that either transportation system can be employed.

3.2.2 PRODUCTION ASSUMPTIONS

One fundamental factor influencing the development plan is the oil reservoir size. In simple terms the oil reservoirs must contain sufficient recoverable oil or reserves to make production and transportation of the oil economic. The exploration program is focused on locating and delineating these types of reservoirs. Determination of the size of the reserves is discussed in Section 4.2.2.

Table 3.2-1 lists three reservoirs in the Beaufort Sea-Mackenzie Delta Region which, based on current information, are nearest to being considered commercially viable. The table lists the discovery date, when delineation wells might be drilled, when artificial islands may be completed and when first production could reasonably be expected. Based on current information regarding reservoir pools in the Beaufort

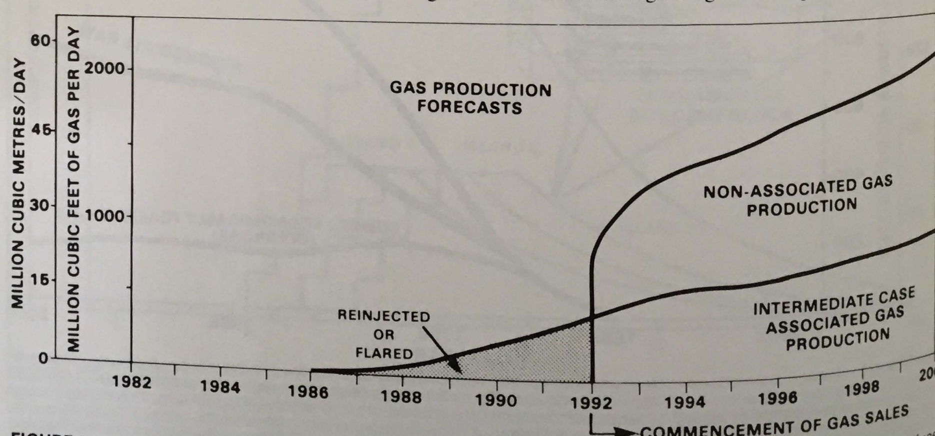


FIGURE 3.1-3 *Two sources of gas are available in the Beaufort Sea-Mackenzie Delta Region. One is gas that is produced along with the oil and the other is gas that is produced from gas fields. Major gas field discoveries have already been made. Non-associated gas production is dependent on the rate of oil production. Gas wil be transported either through a pipeline down the Dempster Highway or Mackenzie Valley, or in liquid natural gas carrying, icebreaking, ships.*

TABLE 3.2-1

BASIC RESERVOIR ASSUMPTIONS

Field	Discovery Date	Assumed Recoverable Oil (million cubic metres) Per Island	Per Field	Date Wells Drilled	Production Islands Required & Completion Date	First Production Date
Tarsiut	1979	20		2 in 82	1 (85)	86*
		20		1 in 83	2 (86)	87
		20		1 in 85 & 86	3 (87)	88
		20		1 in 87	4 (88)	89
		20	100	1 in 88	5 (89)	90
Koakoak	1981	95		1 in 83	1 (88)	89
		95		1 in 85, 86	2 (91)	92
		95	285	1 in 87, 88	3 (95)	96
Issungnak	1981	32		1 in 83, 84	1 (91)	92
		32	64	1 in 85	2 (92)	93

*Using an early production system.

Sea-Mackenzie Delta Region, the development outlined in Table 3.2-1 could lead to a production level of 47,000 cubic metres per day (300,000 barrels per day) by 1990. This represents the intermediate case outlined in Figure 3.1-2.

The largest potential recoverable oil reserves appear to be located offshore in the Beaufort Sea rather than onshore in the Mackenzie Delta. Offshore oil discoveries include Nektoralik, Kopanoar, Tarsiut, Koakoak, and Issungnak. The success of current delineation drilling programs will determine which of these discoveries is developed first.

To assist in describing the possible scale and rate of development the proponents have used a computer model referred to as the Beaufort Planning Model. It is described in further detail in Section 3.2.8, but some of the assumptions used by it should be outlined at this time. The model assumes that the proponents will proceed with a development scheme after a discovery well and two delineation wells have been successfully drilled. It is further assumed that an artificial island development scheme would be used and that production would commence approximately one year after the production island has been completed. The number of wells that must be drilled in order to deplete full reserves in a reasonable period of time is assumed to depend on well productivity. The number of wells drilled then in turn indicates the level of activity required to meet the development plan.

Other pertinent production assumptions used in the development model are listed below.

1. One commercial discovery results from each ten wildcat exploration wells that are drilled.

2. Production islands located over deep reservoirs (over 3,000 metres) will use 3 drilling rigs per island whereas those located over shallow reservoirs (less than 1,500 metres) will use two rigs per island.

3. Each drilling rig can drill 3 production wells per year to deep reservoirs, 6 wells per year to medium depth reservoirs and 8 wells per year to shallow depth reservoirs.

4. One injection well will be required for every two producing wells drilled.

5. Gas or water injection will commence either 1 or 2 years after the start of oil production.

6. Associated gas production is based upon the assumption that the gas to oil ratio is 178 cubic metres of gas to 1 cubic metre of oil (1,000 standard cubic feet of gas to 1 barrel of oil). More details on gas production are given in Chapter 7.

7. Typically peak reservoir production lasts 3 to 5 years.

8. After peak production, production declines at an annual rate of 15 to 20%.

9. Reserves are depleted in the 25 year design life of an artificial island.

3.2.3 ECONOMIC CONSTRAINTS AND ASSUMPTIONS

By definition, a commercial reservoir is one which has recoverable reserves large enough to yield a sufficient return on the investment required to develop and operate the field. The threshold reserve is the minimum level of reserves which will enable the developer to proceed.

In conventional southern Canadian onshore operations, threshold reserves are very low compared to what is required in more difficult areas like the Beaufort Sea or the North Sea. The minimum crude oil reserves required to make production in the Mackenzie Delta or Beaufort Sea economic will depend on many factors, including reservoir depth, well productivity and areal extent of the reserves. It is not possible to give precise threshold reserves until these factors are determined by delineation drilling and engineering studies.

The transportation system that will be used to carry Beaufort Sea-Mackenzie Delta oil to the south will be a significant factor affecting threshold reserves. Extensive studies are underway to determine threshold reserves and the economic costs of various transportation options. As the cost of the transportation system is reduced, so is the level of threshold reserves required.

3.2.4 ENVIRONMENTAL AND SOCIO-ECONOMIC CONSTRAINTS

Development of the Beaufort Sea-Mackenzie Delta Region must be accomplished within the constraints imposed by the degree of environmental and socio-economic impact which is deemed acceptable. Accordingly, the development will be undertaken in such a way as to take into account environmental and socio-economic concerns. These issues and industry's mitigative measures are dealt with in Volumes 4 to 7 of this Environmental Impact Statement.

3.2.5 REGULATORY CONSTRAINTS AND ASSUMPTIONS

The wide variety of activities involved in a project of this type and size are subject to many public regulatory controls. These controls fall under a range of jurisdictions (local, regional and national) and range from implied or requested controls to specific guidelines and laws. Development must be undertaken within these constraints.

There are a number of government agencies to which industry must submit their proposals for hydrocarbon production from the Beaufort Sea-Mackenzie Delta Region. These include the Environmental Assessment Review Process (EARP); the review of development plans by the Department of Indian Affairs and Northern Development (DIAND); a reveiw of engineering proposals and Canadian benefits under the Canadian Oil and Gas Land Act (COGLA); possibly a review by the National Energy Board (NEB); and reviews by the Northwest Territories and Yukon governments.

The major constraint of regulatory processes is the time necessary for preparation, presentation and approval. One consequence is that project scheduling and major financial commitments are often delayed.

The unique relationship between Arctic seasonal operations and delays should be recognized. A short delay due to the regulatory process could result in a one year delay in development, since the open water season in the Beaufort Sea available for construction and installation of equipment is very short. Delays of this type are costly.

3.2.6 LOGISTIC AND SUPPORT CONSTRAINTS AND ASSUMPTIONS

A variety of assumptions related to support and logistics must be determined in order to evaluate the levels of activity, which in turn, may produce environmental and socio-economic effects.

Dredging, for example, is a key activity which influences the pace of development. Figure 3.2-1 shows the approximate dredging requirements for construction of artificial islands. It should be noted that the volumes needed and their deliverability are directly related to dredge type (capacity), distance from source to deposit, and the water depth at the island location. All these factors influence the time taken to build exploration and production islands.

Personnel requirements are another significant variable which may affect the development plan. The availability of people with the necessary skills is essential to the success of the operation. Assumptions are made about the people required on the basis of job skills.

Assumptions with regard to freight volumes and modes of transport are required for each type of activity. Assumptions are made of where and when materials are required and the means of supply. For example, river barge traffic will increase but this will not affect community resupply since an allowance is made for that. The success of meeting supply commitments will determine the success in keeping to schedules.

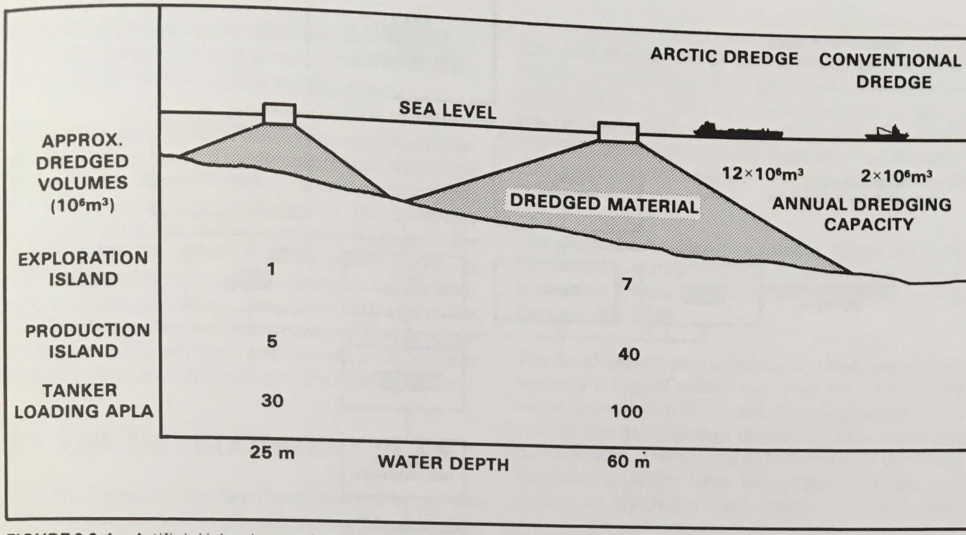


FIGURE 3.2-1 *Artificial islands must be built to develop offshore reservoirs. This requires the dredging of very large volumes of material. This figure shows both dredge capacity and the volumes of dredged material required for typical offshore structures at two water depths.*

The supply of marine vessels, aircraft and land vehicles is also a significant consideration in meeting development schedules.

Large urban centres do not presently exist in the region and consequently support bases must be established. The support bases are the operations centres from which all logistics or support functions originate. Assumptions about type and size of support bases are made on the basis of activities planned, quantities of freight to be moved and available modes of transport.

All logistic and support assumptions are determined by the level of activity, that is, the pace of development pursued. Furthermore, they are all interrelated. Thus, to achieve a higher rate of oil production more drilling is required and more activity occurs at the support base.

3.2.7 POLITICAL CONSTRAINTS

Major developments such as this proposal for the Beaufort Sea-Mackenzie Delta Region must be co-ordinated with national and regional political policies, and this can impose some constraints. However, the plan put forward in this document will help fulfill government policies on resource development and will contribute to meeting the national objective of achieving energy self-sufficiency. As planning progresses, communication with governments and the local people will be maintained, and enhanced if necessary, to ensure compatibility with government policies and other requirements.

Within northern Canada there are many political issues to be settled which have implications for Beaufort Sea-Mackenzie Delta development. Included among these are native land claims, division of the Northwest Territories, provincehood and revenue sharing. However, in the proponents' view these issues need not necessarily impose constraints on this development. Rather, development of the region should have a positive impact on the resolution of these issues. Furthermore, the provision of employment, business and other opportunities, and a tax base will improve the economic base of the region.

3.2.8 THE BEAUFORT PLANNING MODEL

An extensive computer program has been developed, and is presently utilized, to assist in analyzing the development options available for the Beaufort Sea-Mackenzie Delta Region. Figure 3.2-2 is a flow diagram of the computer model. The model allows planners to test various assumptions related to development which assist in narrowing down scenarios to a small group of feasible schemes. However, it must be remembered that computer modelling is a planning tool and the final selection of a development plan for the Beaufort Sea-Mackenzie Delta Region will still be based on discovery rates, operational practicality, technical and economic feasibility as well as social and environmental concerns.

The planning model is not intended to predict a specific development plan but rather to indicate the requirements (within a reasonable order of magnitude) necessary to attain different levels of activity.

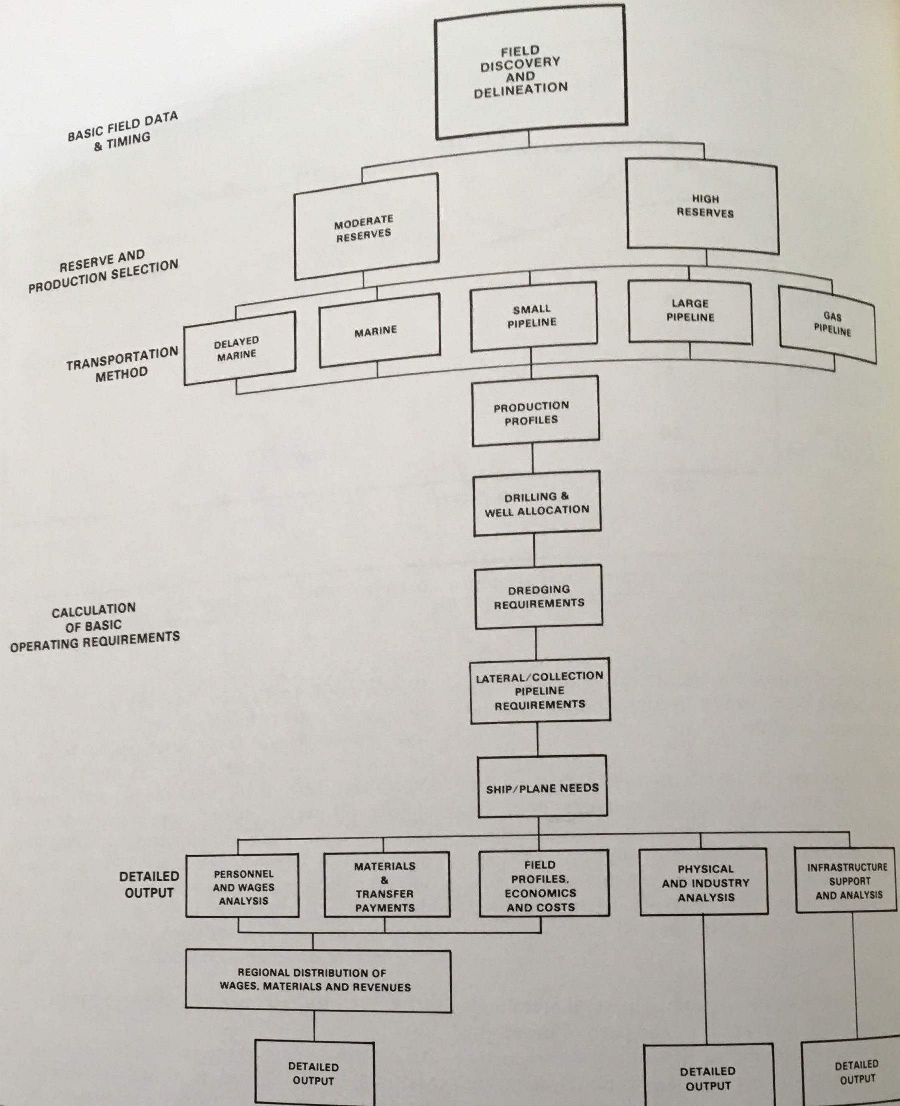


FIGURE 3.2-2 *A planning model assembled on a computer has been developed to relate the many variables involved in the development of discoveries in the future. The model starts with assumptions on the number and size of discoveries and computes the resources such as icebreakers, drilling systems, and people that are required throughout the forecast period. the computer model enables one to study a great many options and determine if the resources are available and also to quantify the factors which may cause an environmental or socio-economic disturbance.*

Thus, a particular exercise might consist of inputting information associated with assumed discovery rates, reservoir parameters and production rates. The model output would then indicate the individual reservoir production profiles and the levels of activity required to attain that particular development rate. Some of the requirements indicated by the output are: dredge volumes, number of islands, number of drill rigs, manpower, steel tonnage, machinery, ships, capital flow and transfer payments. For example, the computer model calculates the personnel requirements on the basis of thirty job skill classifications and estimates the home residences of these workers. This, in turn, determines the infrastructure needed to

transport personnel to the Beaufort Sea-Mackenzie Delta Region as well as the revenue transferred to the provinces through the wage mechanism.

The gathering of relevant data is an ongoing process and the development of the Beaufort Sea-Mackenzie Delta Region depends on constantly updating our knowledge base. The flexibility of the computer model allows planners to continually re-evaluate the requirements for different development plans. In using this model, short term projections are reasonably accurate. However, long-term extrapolations based on these data are less accurate. The development plan described here, and options to it, are thus based on the best currently available information.

3.3 THE DEVELOPMENT PLAN

The development plan can be considered in two distinct phases. In the first phase hydrocarbon resources will be confirmed and delineated and a complete oil producing and transportation system will be designed and built. This is the short-term development plan which leads to 'first oil.' For the intermediate case, first oil using the completed transportation system could be as early as 1986 using tankers or 1987 using an overland pipeline. The plan for the second phase of development is to provide for long-term oil production.

These two distinct phases of the development plan (see Figure 3.3-1) are described here. The planned activities in 1982 are presented,followed by the schedule and description of activities planned to 1986. The likely developments in place and assumed activity underway in 1987 are then presented to give a clear picture of the progress made to that date. This is followed by a more general description of the schedule and activities which could continue to the year 2000.

The development plan presented is based upon the intermediate production rate shown in Figure 3.1-2. In Section 3.4 the options to and influences on this plan are discussed.

The development plan is formulated and described in terms of a typical oilfield development which could occur anywhere in the world. The single unique feature of this development plan is the location of the development. The natural environment of the Beaufort Sea-Mackenzie Delta Region places unique constraints on design and implementation of such a plan.

3.3.1 THE STARTING POINT - 1982

The development plan described here starts in 1982. Delineation drilling to define the offshore discovery at Tarsiut (Figure 3.3-2) is under way in 1982. The commercial viability of this reservoir should be established by the end of the year. Onshore, further exploration or delineation drilling can also be expected in 1982.

Elsewhere in the region in 1982, three offshore wells are scheduled to be completed that were suspended at the end of the 1981 drilling season. Up to six addi-

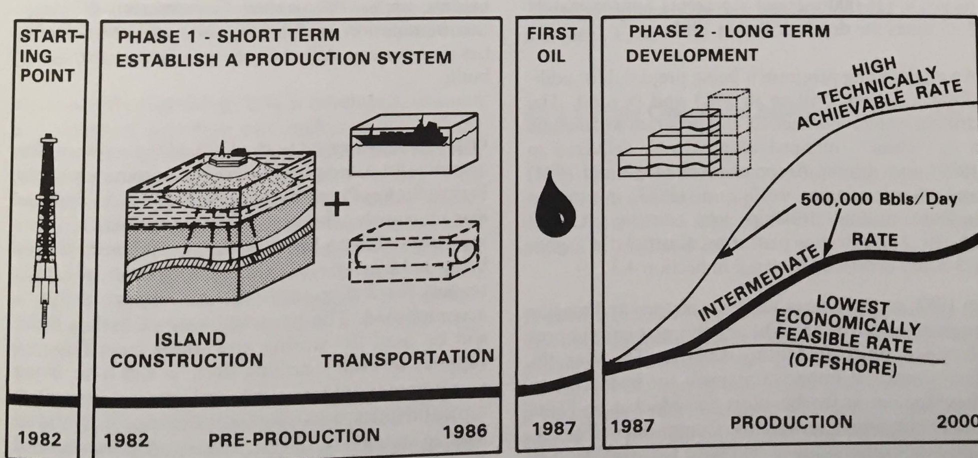


FIGURE 3.3-1 *After a discovery has been made there are two distinct phases of activity. The first is development where the production facilities are built and installed and the transportation system is put in place. The second phase is production. It requires about four years to develop a typical offshore oil field. The number of oilfields being developed at any one time in a given area is the pace of development. Production could start from the Beaufort in 1986.*

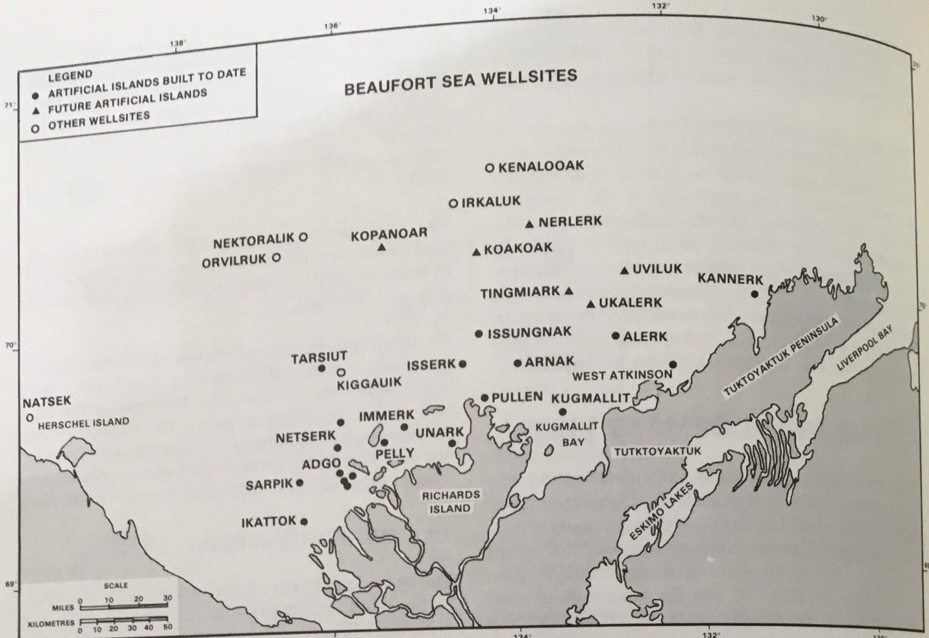


FIGURE 3.3-2 *Wellsites in the offshore Beaufort Sea.*

tional wells could be started during the season if time and conditions permit. Completion of this drilling program (16,000 metres) represents approximately 2.25 times the depth drilled in 1981.

An engineering program is being prepared for additional offshore drilling in 1983 and beyond. The drilling systems planned for this program will include a new caisson retained island (to be delivered in 1982), two mobile Arctic caissons (1982 and 1984) and a floating conical drilling unit (1983), in addition to conventional drillships and existing artificial islands. These drilling platforms, illustrated in Figure 3.3-3, are described in detail in Section 4.3.

In 1982, support bases will be expanded and marine equipment will be brought into the region to support these and anticipated future activities. This year, the Environmental Impact Statement for hydrocarbon development in the Beaufort Sea-Mackenzie Delta will be submitted by industry. Commitments for certain kinds of equipment will have to await the outcome of this review process.

Gulf is developing a base on Arctic Transportation Limited property at Tuktoyaktuk which will accommodate up to 200 people. Construction of living accommodation, warehouse, shop and utility facilities is underway. A fuel depot tank farm is also being built.

Gulf has also applied to the Federal Government for approval-in-principle to develop a marine supply base at Stokes Point on the Yukon coast. An application previously submitted to the government requesting permission to build a base at McKinley Bay is being held in abeyance until resolution of Gulf's request for a deep-draft marine support facility is accomplished. The proposed base at Stokes Point will be used for storing and transferring fuel and supplies to Gulf's drilling fleet. It will have living accommodation for camp and marine personnel, repair facilities, a warehouse and storage area and an airstrip suitable for STOL aircraft. A causeway and dock is being planned to provide ice protection and to permit loading and unloading of supplies.

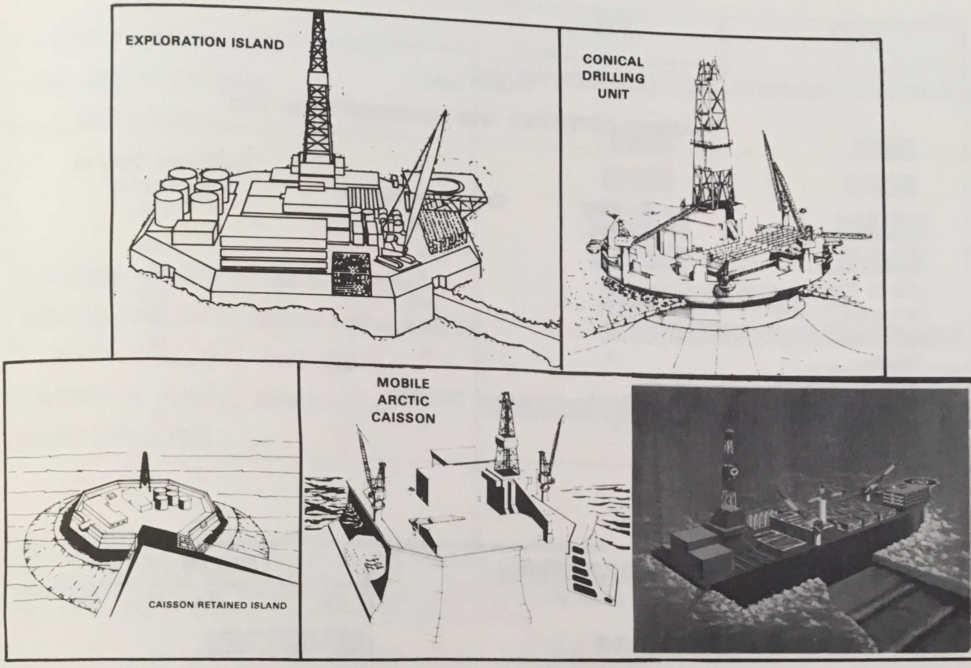


FIGURE 3.3-3 *Drillships and artificial islands have been used as foundations for exploration drilling rigs in the Beaufort for the past several years. Variations of these concepts include artificial islands, which are capped with different types of caissons, and conical floating systems, which have the capability to drill in more ice than a drillship. Exploration drilling systems are temporary in nature, generally drilling only one well and then moving to a different location.*

Several new marine vessels will be brought into the Beaufort Sea in 1982 as well as several new aircraft. Table 3.3-1 summarizes the major industry activities planned and the support equipment required for 1982.

Although the technology is now developed, research will continue to refine our understanding of the effects of sea ice on the offshore structures. In 1982, research and monitoring (described in Volume 7) will be carried out in a variety of fields including studies on waves and currents, earthquakes and geotechnical research related to offshore drilling and production platforms; well drilling research; oil spill research related to prevention and mitigation of possible spills; and environmental research and monitoring related to all activities.

The level of activity planned for 1982 is not appreciably greater than that of previous years, but will reflect the start of planning and preliminary design to progress from the exploration phase to the production phase.

3.3.2 DEVELOPMENT PLAN - 1982 TO 1987

The development schedule for 1982 to 1987 is shown in Figure 3.3-4.

3.3.2.1 Prove Commercial Reserves

The proposed drilling program for 1982 onwards is designed to discover and prove commercial reserves of oil. Figure 3.3-5 illustrates systems to be used for drilling in 1982 and 1983.

Present indications are that commercial reserves of oil exist in Beaufort Sea reservoirs and that these will provide the threshold oil quantities required to initiate production development. The development plan assumes that reservoirs will be developed and placed on production in order of technical merit and reservoir knowledge. However, shallow water reservoirs (developments in less than 25 metres) will

TABLE 3.3-1

PLANNED ACTIVITIES AND EQUIPMENT FOR 1982

Component	Existing (approx.)	Estimated New In 1982	Estimated Total to the End of 1982
Wells Drilled	133	9	142
Islands Constructed	20	2	22
Personnel on site	1,170	260	1,430
Marine Vessels	29	7	36
Aircraft	11	4	15
Supplies Required (Tonnes/Annum)	149,000	200,000	
Support Bases	2	1	3

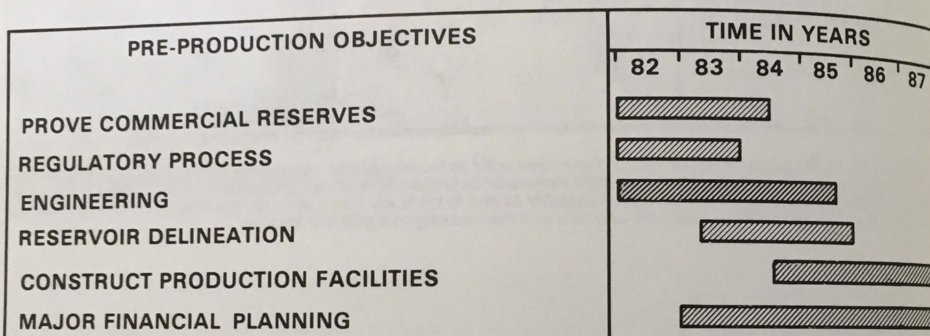


FIGURE 3.3-4 *The development schedule indicates that the major financial commitments must be made in early 1983 in order to achieve production in 1986. The commercial viability of some discoveries should be established by that time.*

be less difficult to bring on production than deep water ones (more than 50 metres). This is largely because in shallower waters much less dredged material will be required to build the necessary artificial islands for drilling and production platforms. Likewise, finding oil at shallow depths (less than 2,000 metres beneath the sea bed) will make such fields easier to develop than fields with deeper reservoirs because drilling time and costs will be reduced.

As a consequence of these considerations, the exploration and drilling program is expected to concentrate on delineating reservoirs such as Tarsiut and Issungnak (shown in Figure 3.3-2). These reservoirs are located in relatively shallow water (less than 25 metres deep) with discovery reservoir depths at roughly 1,500 metres. Exploratory and delineation drilling will continue at other locations, including Kopanoar and Koakoak, to fulfill company obligations and to assess potential reservoirs in these portions of the lease acreages.

Several crude oil discoveries have been made in the onshore and nearshore Beaufort area since the discovery at Atkinson Point in 1970. To date, a total of 9 oil pools in the shallow water and onshore area have been discovered, with total recoverable reserves being estimated at between 30 and 40 million cubic metres. There is significant potential for future crude discoveries in the onshore region, however these will likely be more modest in size than those discovered offshore.

3.3.2.2 Regulatory Process

Submissions will be made to government and the Federal Environmental Assessment and Review

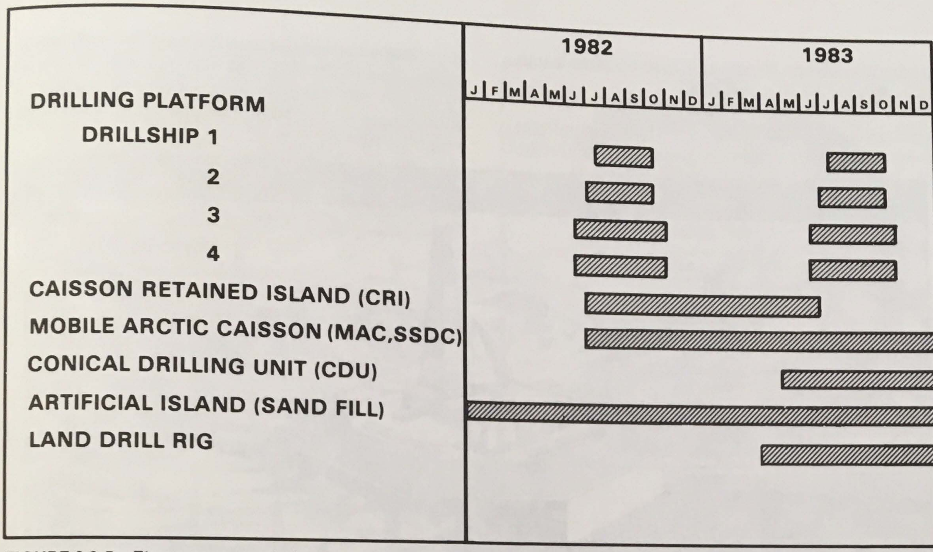


FIGURE 3.3-5 *There are currently four drillships operating in the Beaufort Sea and one caisson retained artificial island. Three additional caisson drilling systems are under construction and will come into the Beaufort in '82 through '84. A conical drilling unit is also under construction and scheduled to come into the Beaufort in 1983. The delineation requirements for existing discoveries increases the requirement for drilling systems.*

Process will be completed in this time period, as discussed previously.

3.3.2.3 Engineering

If drilling is successful in 1982, detailed engineering for at least one oil production system will begin. Early efforts will concentrate on the detailed design of site specific production platforms, an initial oil production system and a long term transportation system. As shown in Figure 3.3-6, a complete production system will then be in place.

A significant difference between the exploration and production phase of oil field development is the degree of permanence of the facilities. For example, offshore exploration islands are designed for a shorter design life (2-3 years) than will be necessary for

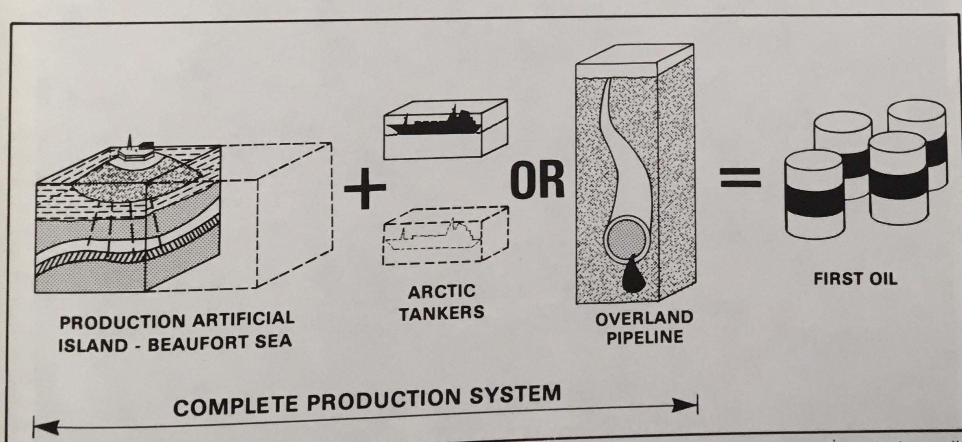
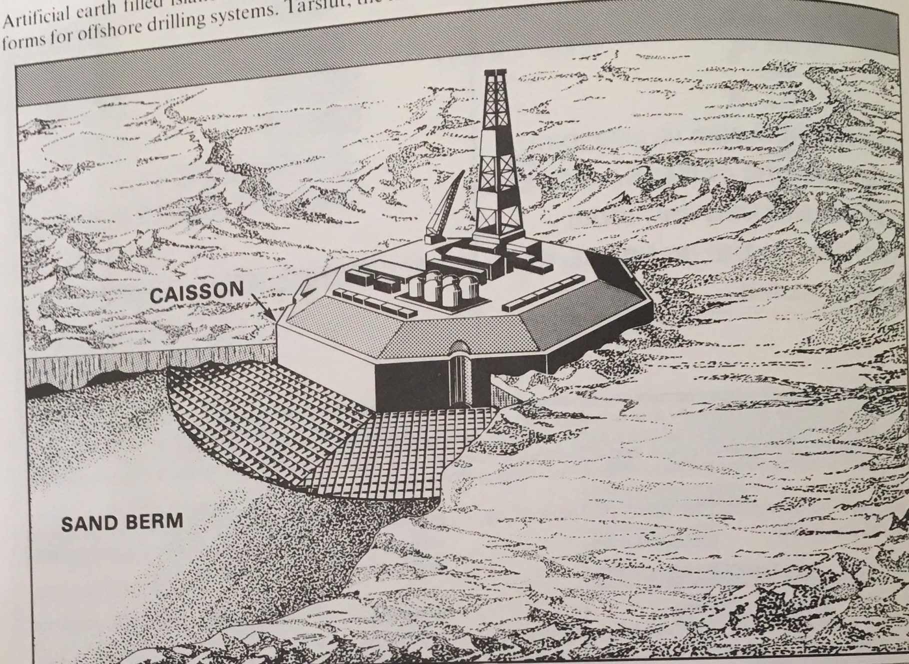


FIGURE 3.3-6 *The major components of a production system include drill systems for drilling and producing wells, production processing facilities, various support systems, a foundation system on which to place this equipment, and an oil transportation system. Artificial islands will be used as a foundation for the drilling and production systems, while either tankers or pipelines are suitable for hydrocarbon transportation.*

production islands. Production systems must last the 20 to 30 year life of an oil field.

Artificial earth filled islands are the principal platforms for offshore drilling systems. Tarsiut, the first caisson-retained island, was built in 1981 in the moving ice zone of the Beaufort Sea. Figure 3.3-7 shows an artist's cut-away drawing of this island and a photograph of the island in operation during the winter of 1981-82.



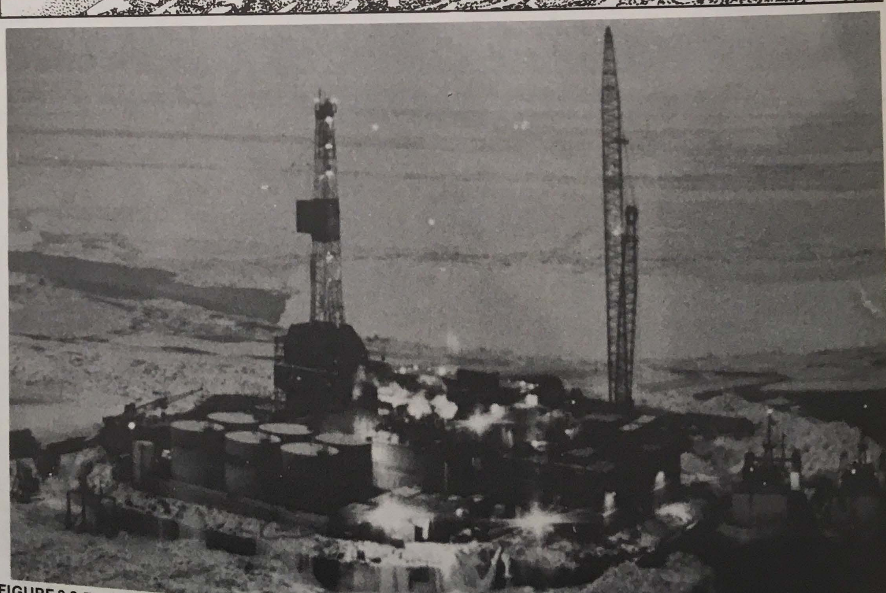


FIGURE 3.3-7 *Experience with exploration islands has demonstrated the feasibility of using artificial islands as a foundation for permanent production and drilling facilities. The Tarsiut concrete caisson retained island built in 1981, provides the engineers with technical data required for designing larger permanent production islands.*

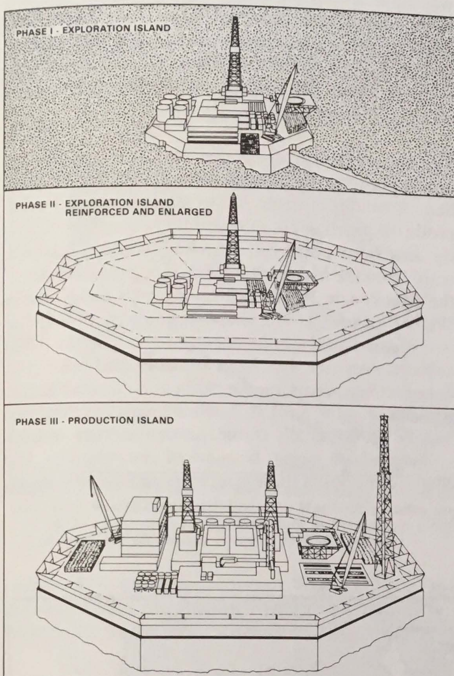


FIGURE 3.3-8 *An exploration island like Tarsiut could be converted to a production island by enlarging and strengthening the existing island as illustrated in this sequence.*

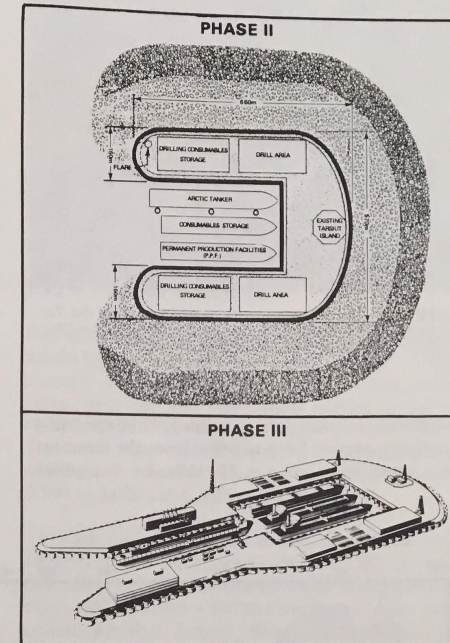


FIGURE 3.3-9 *The Tarsiut exploration island could also be enlarged to an offshore production and loading facility. This facility includes oil storage, processing and loading facilities as well as the drilling systems. The slot in the island provides protection for the storage and production systems and for tankers which would load at the island. The ice thickness inside the island is controlled by waste heat from the production process.*

Experience with artificial island building during the last ten years is being used in the design of production islands. At present there are two main concepts for production islands. One is a circular island of sufficient size to support production equipment. Figure 3.3-8 illustrates a possible sequence for upgrading an exploration island to a production island.

Another concept of a production island is horseshoe shaped. This design, as shown in Figure 3.3-9, permits the use of conventional floating or fixed facilities in the centre since the island would isolate these facilities from high ice forces.

The technology used in constructing land pads for production facilities would be similar to methods used at Prudhoe Bay, Alaska. Either gravel pads or piling would be installed to prevent permafrost degradation. All of the production platforms, as well as several other types of foundations, are described in more detail in Section 4.3 of this document.

Early design efforts have and will continue to concentrate on the facilities and equipment that will be placed on the above mentioned platforms. These facilities are conventional and, when housed to provide protection from the weather, will operate in the same way as similar systems throughout the world. Types of production facilities and their purpose are described in more detail in Section 4.5.

In 1983 planning and engineering will also focus on the options for an oil transportation system. With reference to the tanker option, engineering studies will focus on the design of the Arctic tanker and the offshore loading facilities which will be required in the Beaufort Sea. These are discussed further in Section 6.3. With respect to the development plan it is assumed that tankers can be built in the next four years and that they will transport crude oil year-round through the Northwest Passage. Dome is currently proposing to use a "smaller" version of the Arctic Class 10 tanker to transport early production from the Tarsiut field (Plate 3.3-1).

Another transportation option is an overland pipeline. The route presently being considered follows the Mackenzie Valley to northern Alberta. It parallels the Rainbow Pipeline system to Edmonton where it connects with existing pipeline systems. This route is shown in Figure 3.3-11.

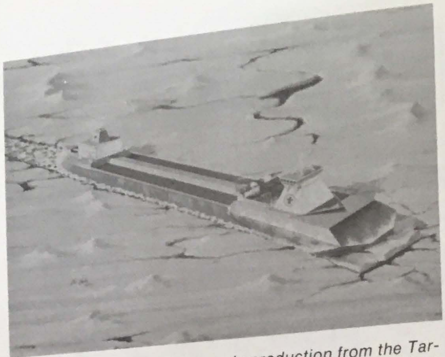


PLATE 3.3-1 *To transport early production from the Tarsiut field, a "smaller" 80,000 tonne version of the Arctic Class 10 tanker is being actively considered.*

The design, construction technology and operating experience needed for a pipeline from the Beaufort Sea is already in existence. The Alyeska oil pipeline was built across the entire state of Alaska and has been successfully operated since June 1977. This Alaskan pipeline is approximately 1,300 kilometres in length, 1,200 millimetres in diameter, and is presently carrying about 250 thousand cubic metres of oil per day (1.6 million BOPD).

The present development plan considers two pipeline configurations for transport of oil from the Beaufort Sea. A small diameter 300 to 400 millimetre buried crude oil pipeline could be built to carry low viscosity, low pour point oil. This line would run southward from the Mackenzie Delta along the east side of the Mackenzie River and connect to the Norman Wells Pipeline. This transportation system is being investigated and could accommodate up to 3,500 cubic metres per day from onshore and nearshore Beaufort Sea oil discoveries such as Adgo and Atkinson (see Figure 3.3.12). Such a small development may be economically viable, particularly for onshore and nearshore fields, because of the relatively low cost of developing these reservoirs and the efficiencies

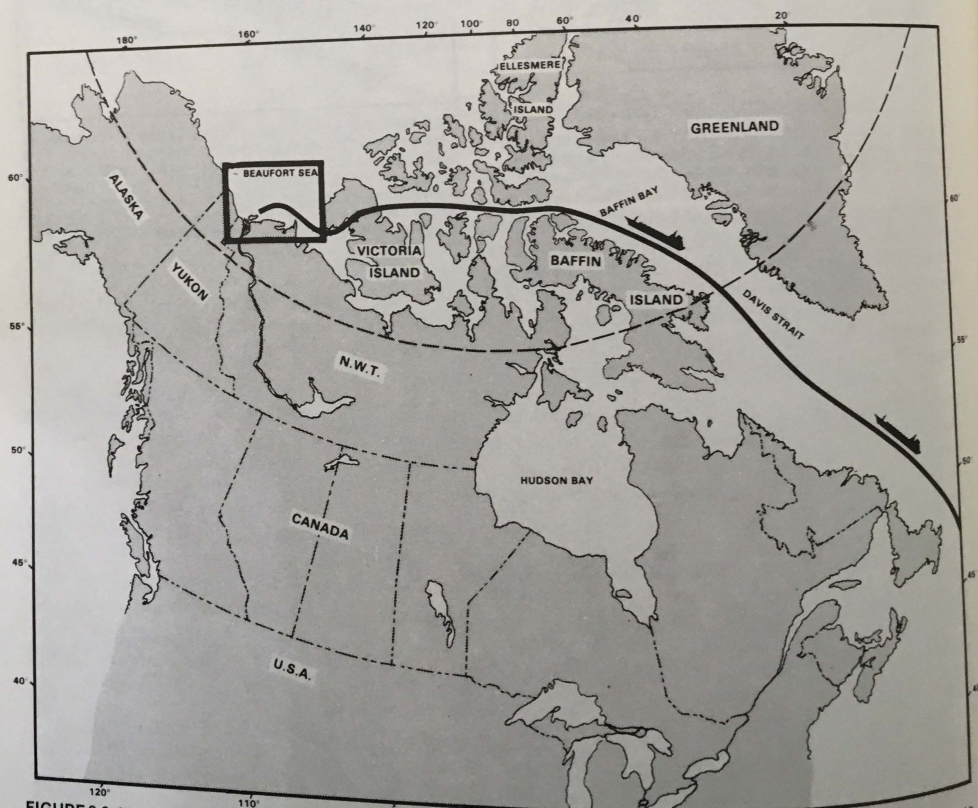


FIGURE 3.3-10 *The Northwest Passage will be the route used by the Arctic Tankers to transport oil from the Beaufort Sea to the East Coast of North America.*

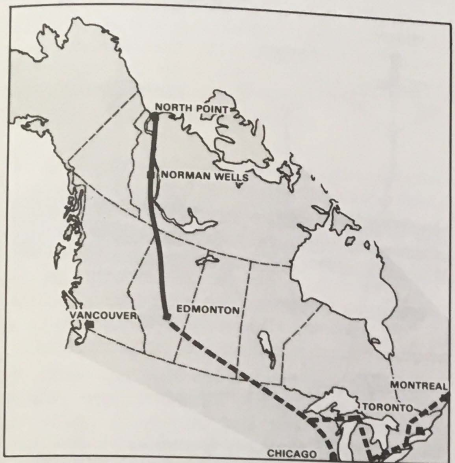


FIGURE 3.3-11 *If a pipeline were used to carry oil from the Beaufort it would be routed down the Mackenzie Valley and tie in with an existing pipeline system at Edmonton which would carry the oil east to Toronto and Montreal.*

achieved by using the Norman Wells pipeline. It is estimated that production could commence 3 to 4 years after regulatory approvals were received.

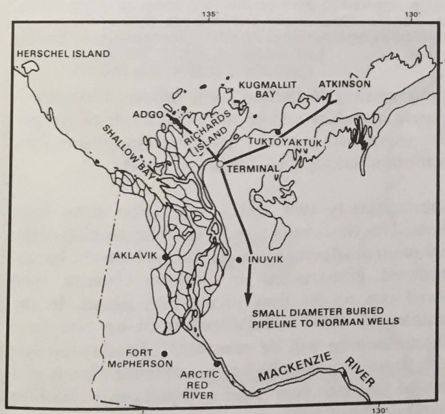


FIGURE 3.3-12 *Early onshore oil development.*

As larger offshore reserves are proven, a new larger pipeline (900 or 1200 millimetres in size) may be built from a site such as North Point on Richards Island to Edmonton. This line would also transport oil previously carried by the small diameter pipeline if that were built. The small pipeline could then be used to carry fuel gas for pump stations, natural gas liquids or methanol produced from natural gas.

In this time period, engineering studies of a mixed mode transportation system will be conducted. Initial oil production might best be transported by either a small diameter pipeline or by tankers. Then for increased production, there would still be a choice of transportation system: either a large diameter pipeline or an increase in the number of tankers. However, support for either or both transportation systems by the Government of Canada must be forthcoming so that an essentially complete oil production system can be built.

3.3.2.4 Reservoir Delineation

Delineation drilling of the major discoveries onshore would be accomplished over a two year period. For example, four wells have been drilled to date on the Adgo structure and delineation drilling could be completed by 1984 with expected production in 1987. The development would include 3 gravel production islands with a total of 15 producing wells to produce 2,500 to 3,000 cubic metres per day.

Through further delineation drilling and reservoir analysis carried out between 1982 and 1987, the specific offshore locations around which initial production could commence will be identified. Present indications are that Tarsiut, shown in Figure 3.3-13, could be the first offshore commercial reservoir.

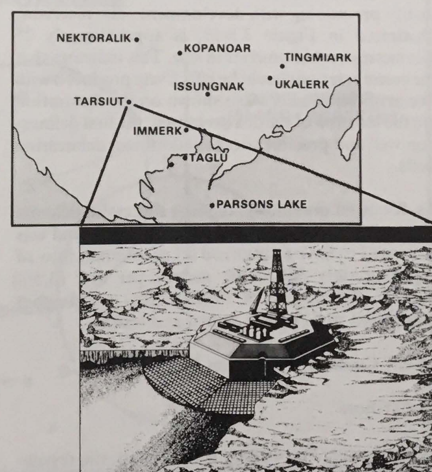


FIGURE 3.3-13 *A successful delineation well was drilled from an experimental island at Tarsiut during the winter of '81-'82. Further drilling is planned during the summer of 1982 so that the commercial viability of this field could be established by the end of 1982.*

The development plan schedule for the offshore Beaufort Sea is summarized in Figure 3.3-14. The proposed plan is to develop the Tarsiut reservoir first

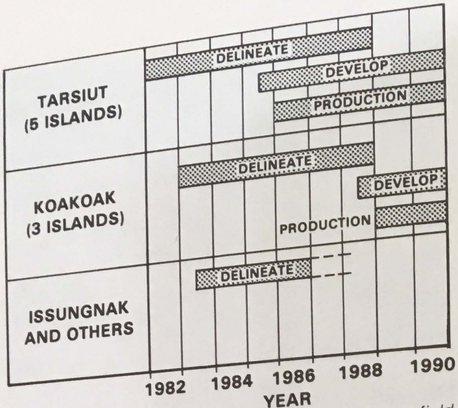


FIGURE 3.3-14 *Tarsiut will likely be the first offshore field on production in the Beaufort. It is located in relatively shallow water, already has an artificial island, and has a successful delineation well. Development of other Beaufort discoveries could follow Tarsiut, sequenced to maximize the utilization of onsite construction resources and stabilize the activity in the Beaufort Region.*

followed by other likely fields such as Koakoak, Issungnak and Kopanoar in a systematic fashion.

The water depth at Tarsiut is relatively shallow (22 metres), making building of a production island feasible. The discovery hydrocarbon zone is at roughly 1,500 metres. The reservoir structure indicates that only a few delineation wells would be required to justify proceeding with development. The reservoir, illustrated in Figure 3.3-15, is approximately 25 kilometres by 4 kilometres in size. This indicates that the entire reservoir could be effectively produced with five artificial islands. Also shown on the illustration are the location of the discovery well, the first delineation well and possible sites for additional delineation wells.

As discussed previously, the first successful delineation well at Tarsiut was recently completed and was estimated to have a sustained oil production flow of approximately 550 cubic metres per day (3,500 BOPD). By the end of 1982 at least two further delineation wells will be drilled and tested.

3.3.2.5 Construct Production Facilities

(a) Offshore

Assuming that the drilling is successful, the regulatory process is completed, and financial commitments are made, then the Tarsiut exploration island could be upgraded to a production island. A commitment to an initial transportation system could then also be made.

It is estimated that the volume of dredged material required for the series of artificial islands at Tarsiut is

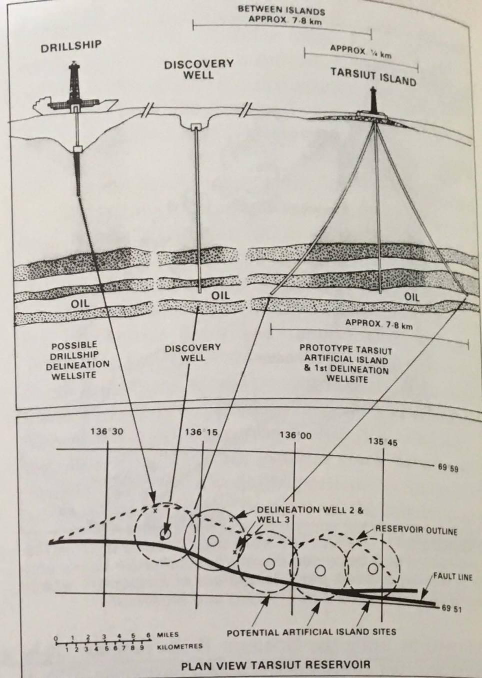


FIGURE 3.3-15 *The Tarsiut discovery well was drilled from a drillship. The delineation well, drilled from an experimental island, was 7.8 kilometres east. The reservoir is relatively long and narrow and relatively shallow. Four to six islands will be required to develop the field because of the limited reach of the directionally drilled wells. One of the islands would be a combination production, processing and loading facility.*

approximately 36 million cubic metres. First development islands would be started at a rate of one per year using conventional dredging equipment with each island taking 2 to 3 years to build.

Approximately two and a half years have been allowed for the fabrication and commissioning of the first main production unit. It will probably be barge-mounted, constructed in southern Canada, then towed out to the first production island. In the summer of 1986 installation, hook-up and final commissioning will be completed. Production systems would be installed on completed islands at a rate of one per year until completion of the fifth island in about 1991.

At the Tarsiut field all production locations will be connected to the main facility by subsea pipelines. Islands will be connected as they are completed. If tankers are used to service this field, their number would increase at a rate of one ship per 8,000 cubic metres (50,000 barrels) of oil per day.

Once the commitment to a production system has been made then development would proceed at the

next reservoir. Based on information to date, this is likely to be Koakoak. This structure is approximately 10 kilometres in diameter and is located in water from 40 to 48 metres deep. Figure 3.3-16 shows the reservoir with the possible locations of development islands.The full development of this reservoir will require three production islands.

The development proposed for Koakoak represents a typical schedule for a moderately deep water field. Drilling should commence in late 1983 and four delineation wells should be drilled and tested by the end of 1988. It is anticipated that these wells will provide sufficient information to determine the commercial viability of this field and to permit construction of a production island to proceed.

The third reservoir to be brought into production could be either Issungnak or Kopanoar depending on relative economics and reservoir potential. Issungnak is in a similar water depth to Tarsiut while Kopanoar is a deep water field.

To establish and then maintain the plan for 1982 to 1987 will require extensive support services. Support services are comprised of all systems that are external to the operating sites. They include such things as support bases, tug boats, supply boats, icebreakers, fixed wing aircraft, helicopters and communications. These are described in detail in Chapter 5.

The number of operating sites and the level and nature of activity at each site determines the amount of support required. For example, an operating drillship requires one icebreaking supply boat and one standby boat. One 20 passenger helicopter is required for every 400 people and one Boeing 737 jet aircraft or equivalent is required for every 2,500 people in the area. These types of relationships are used to calculate future support requirements.

Support base expansion in this time period will be focused at McKinley Bay and possibly Stokes Point. Once the production systems are in operation, some of the functions carried out at the support base may shift offshore to the artificial islands. These islands will be accessible to icebreakers and supply ships on a year-round basis.

(b) Onshore and Nearshore Production

Development of onshore reserves will take place in a manner similar to offshore development. Once reservoir delineation is completed, design, fabrication and installation of production facilities is commenced. The production facilities will be located on gravel pads or piling to guard against permafrost thaw. The

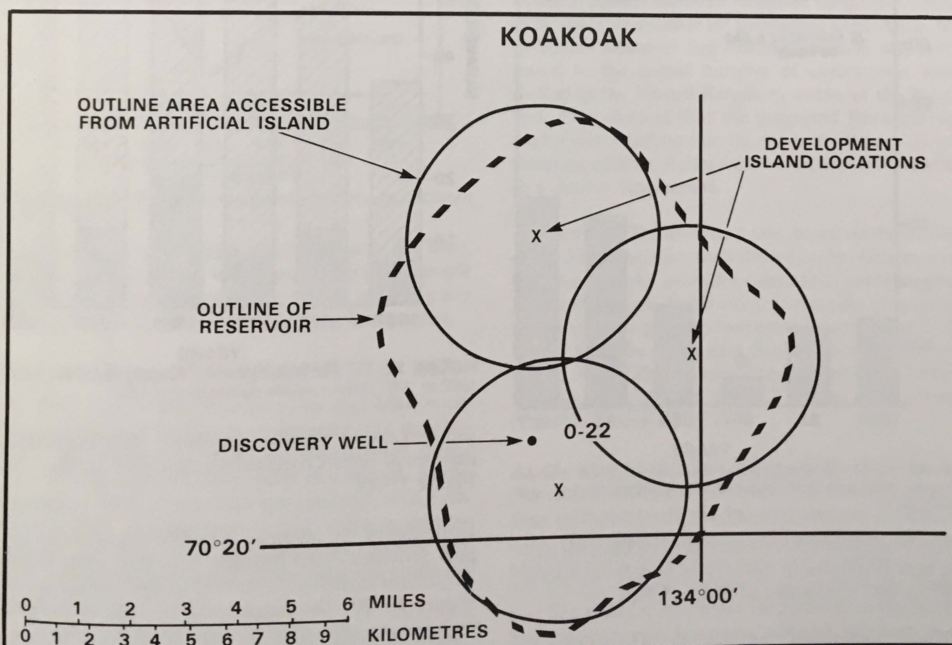


FIGURE 3.3-16 *The Koakoak reservoir is in water about 50 metres deep. The field could be developed with two or three artificial islands and production could be processed at a Koakoak production storage and loading island or alternatively it could be delivered to the Tarsiut loading facility through a seafloor pipeline.*

production facilities will be similar to offshore production facilities, except they will likely be smaller in scale because of the generally smaller reservoir sizes anticipated onshore.

When sufficient reserves have been established to justify investment in gathering and trunk lines, development of onshore reservoirs will proceed. Production from onshore fields could be collected through a gathering system that would transport the oil to either an overland pipeline system or to an offshore loading terminal.

3.3.2.6 Levels of Activity from 1982 to 1987

Figures 3.3-17 to 3.3-21 illustrate some of the levels of activity projected for the period 1982 to 1987, based on the intermediate production rate. These figures were derived using the Beaufort Planning Model (1982). A more detailed description of the possible levels of activity is given in Section 3.5.

Figure 3.3-17 shows the estimated number of oil and gas wells on which drilling is to be started between 1982 and 1987.

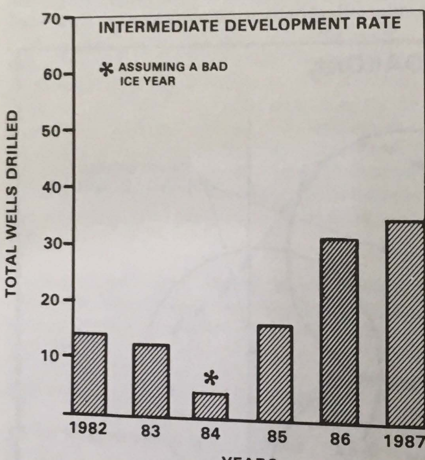


FIGURE 3.3-17 *The estimated total wells to be started between 1982 and 1987 (intermediate production rate) are illustrated.*

The estimated number of islands to be built for drilling and development operations in each year from 1982 to 1987 are shown in Figure 3.3-18.

Offshore operations, whether for exploration or production, will require the support of a fleet of marine vessels. These will include, for example, crane barges and dredges for construction activities, supply ships, tugs and barges to transport materials, and

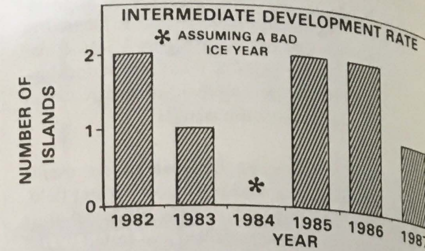


FIGURE 3.3-18 *Artificial island construction estimated for the years 1982 to 1987 is illustrated (Intermediate development rate).*

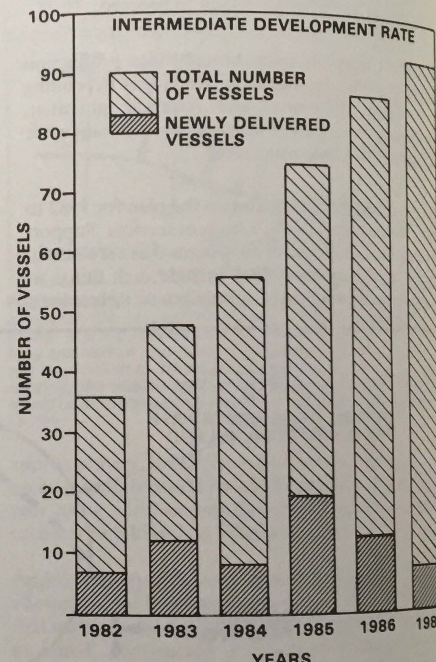


FIGURE 3.3-19 *Projected Marine Vessels required from 1982 to 1987 (Intermediate development rate).*

icebreakers to protect drillships. The estimated number of vessels required for each year are given in Figure 3.3-19.

Estimates of the tonnage of freight required to support activities in the Beaufort Sea-Mackenzie Delta Region for each year from 1982 to 1987 are shown in Figure 3.3-20. The breakdown by type of freight, including an allowance for resupply to the communities in the area, is also given.

Figure 3.3-21 shows the estimated personnel requirements for the oil and gas industry in the Beaufort Sea-Mackenzie Delta Region up to 1987. The num-

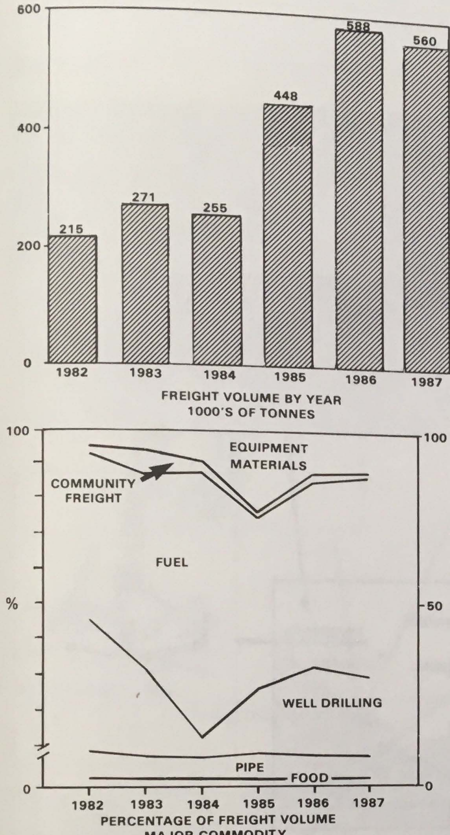


FIGURE 3.3-20 *Projected tonnes of supplies required from 1982 to 1987.*

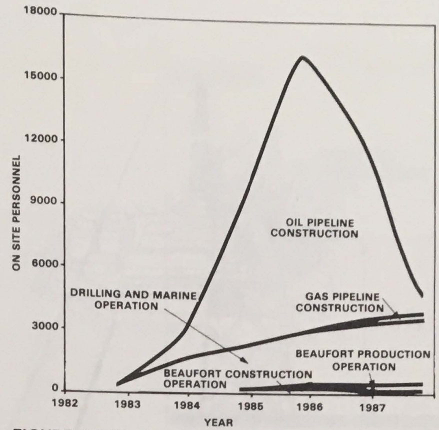


FIGURE 3.3-21 *Shown here are the onsite personnel requirements for the Beaufort Sea-Mackenzie Delta development to 1987. Since a rotation system will be used with some people commuting from southern Canada, the total number of people on the industry's payroll will be larger than this.*

bers shown are for people working onsite at one time. Since a rotation system will be used with some people commuting from southern Canada, the total number of people on the industry's payroll will be greater.

3.3.3 THE PACE OF DEVELOPMENT IN 1987

By 1987, one or two Beaufort Sea and Mackenzie Delta oil fields will have been brought into production. Through exploration, additional commercial reserves will have been discovered. Some experience with production systems will have been gained. The environmental and socio-economic impacts will have been identified and Canada will have a much better picture of the national crude oil supply-demand balance.

In 1987, assuming the intermediate production rate, oil production is projected to be 5,720 cubic metres (38,000 barrels) per day. A complete array of exploration, production and support systems, as illustrated in Figure 3.3-22, will be in place. These are listed in Table 3.3-2.

A method of evaluating the reasonableness of development projections is to compare them with actual experience in another oil producing area. Thus, the projected Beaufort Sea drilling schedule was compared to the actual number of exploration wells drilled in the United Kingdom sector of the North Sea. This showed that the projected Beaufort Sea exploratory drilling rate for the next 10 years is less than one quarter of that experienced in the North Sea in a similar time period.

The Beaufort Sea discovery rate, based on the success of the 33 exploratory wells drilled in the offshore over the past decade, provides substantial evidence that large oil and gas fields exist. If the rate of reserves discovery is as good as that experienced in the U.K. North Sea, then Beaufort Sea discovered reserves would total 720 thousand cubic metres (4.5 billion barrels) of oil by 1985, and 1.2 million cubic metres (7.5 billion barrels) by 1990.

At the time of the first major oil discovery in the North Sea (1970) the site specific technology to produce oil in this harsh marine environment did not yet exist. Nevertheless, first oil production was achieved just five years later and is now well established (Figure 3.3-23). The oil industry's position in the Beaufort Sea today is much like its position in the North Sea ten years ago. Extensive research has been conducted on design criteria for Beaufort Sea systems and experience has been gained in exploratory operations. Based on this experience industry is convinced

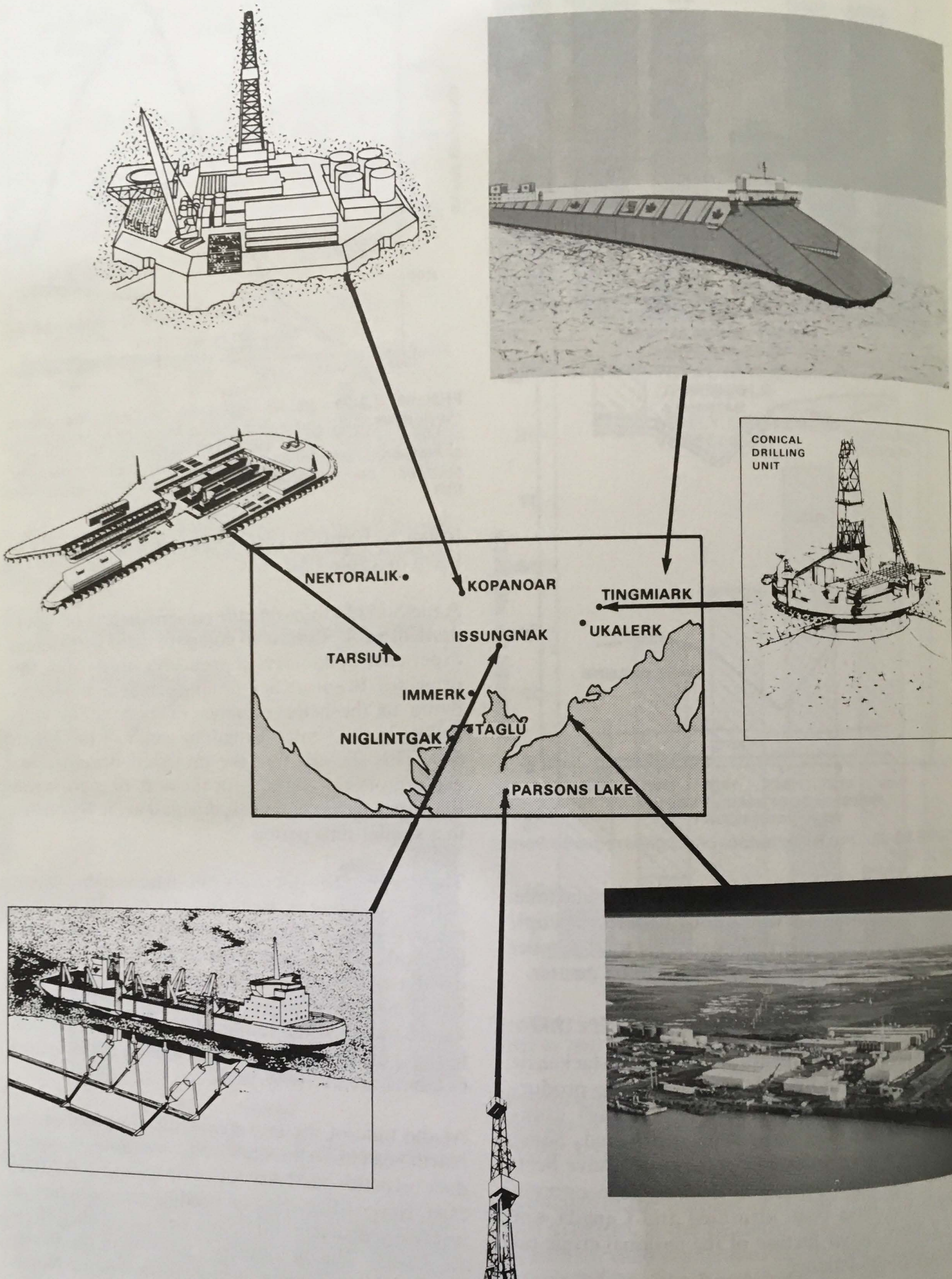


FIGURE 3.3-22 *By 1987 there will be a complete array of exploration, production and support systems in place in the Beaufort Sea-Mackenzie Delta Region, as illustrated.*

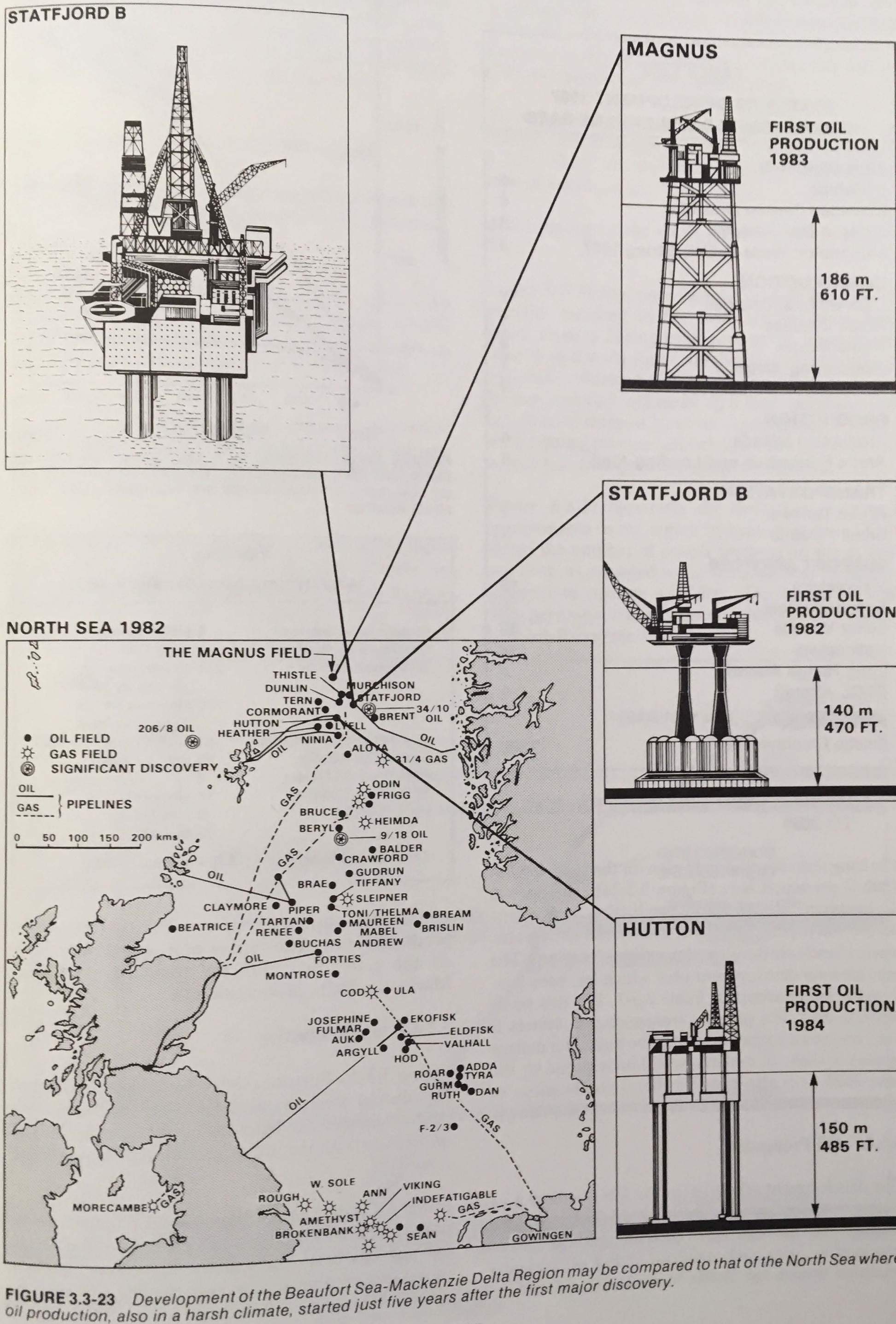


FIGURE 3.3-23 *Development of the Beaufort Sea-Mackenzie Delta Region may be compared to that of the North Sea where oil production, also in a harsh climate, started just five years after the first major discovery.*

that Beaufort Sea oilfields can be brought into full production by 1987.

TABLE 3.3-2 STATUS OF DEVELOPMENT 1987 INTERMEDIATE DEVELOPMENT RATE	
EXPLORATION	
Drillships	4
Extended Season Drillships	4
Caisson Drill Systems	3
Exploration Wells Drilled during 1987	8
CONSTRUCTION	
Conventional Dredges	7
Arctic Dredges	1
Crane Barges	3
Pipe-Laying Barges	1
Accommodation Barges	3
PRODUCTION	
Production Islands	4
Arctic Production and Loading Atoll	1
TRANSPORTATION	
Arctic Tankers	1
Small Pipeline	1
SUPPORT SERVICES	
Icebreakers	16
Supply Vessels	16
Other Vessels	36
Helicopters	14
Long Range Aircraft	4
STOL Aircraft	9
PERSONNEL	
Onsite Employment	3800

3.3.4 HYDROCARBON PRODUCTION 1987 TO 2000

The long term development plan for the years 1987 to 2000 is presented here (Figure 3.3-24). The pace of development, and therefore production, in this time period will depend on further discoveries and on how many islands are developed at various locations. The intermediate development plan which has been projected is summarized in Table 3.3-3. For this intermediate plan, if a pipeline transportation system is used one or two pipelines might be built. If a marine system is used, 16 tankers would be required by the year 2000. It is also possible that a combination of these two systems could be used.

3.3.4.1 Oil Production

The development schedule for the intermediate production rate is shown in Figure 3.3-25. Reservoirs are brought into production in sequence and the sum of production from each artificial island offshore, or

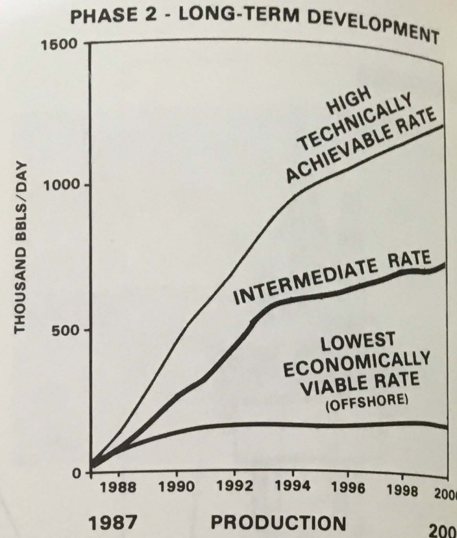


FIGURE 3.3-24 *The long term development plan for the years 1987-2000 will depend on further oil discoveries and on how many artificial islands are developed at each offshore location.*

TABLE 3.3-3 INTERMEDIATE DEVELOPMENT PLAN	
Potential Oil Reserves	6 billion barrels
Developed Oil Reserves	5 billion barrels
Oil Production Rate	270 thousand barrels per day by 1990
	770 thousand barrels per day by 2000
Cumulative Oil Production	6.5 billion barrels by 2000
Exploration Activity	98 wells by 2000
Developed Oil Fields	7
Production Platforms	17 offshore
	8 onshore
	25 by 2000
Total On-Site Personnel	8,700 approx. by 2000

well cluster onshore, results in the total reservoir production rate. The sum of production rates from all the reservoirs gives the total Beaufort Sea-Mackenzie Delta production rate.

3.3.4.2 Gas Production

Figure 3.3-26 illustrates the expected gas production rate during the time period 1987 to 2000. Gas will become available either as associated gas, that is, gas in solution with the oil, or produced as separate gas reservoirs.

Initial gas production will be utilized as fuel wherever possible. Quantities produced in excess of fuel usage will be flared in the early stages of production at each island (approximately 2 years). However, as soon as

technically feasible and economically viable, gas will be re-injected for gas conservation and reservoir pressure maintenance. Many gas transportation options will be assessed prior to sales volumes becoming available. This is discussed in Section 6.2.

3.3.4.3 Levels of Activity from 1987 to 2000

The levels of activity for certain key operations in the period 1987 to 2000 are illustrated in the following figures.

During the period 1987 to 2000, approximately 655 oil and gas wells could be drilled (Figure 3.3-27). These include production, exploration, delineation and injection wells, as discussed in Section 4.4.

The estimated requirements for offshore exploration and production platforms to support the drilling and production activities is shown by year in Figure 3.3-28.

Some islands will first be used as exploration platforms, then upgraded to production islands as appropriate. Deep water production islands require at least two years for construction. One island could be upgraded to an Arctic Production and Loading Atoll (APLA) prior to first oil production. A second APLA will be needed when daily oil production reaches approximately 110,000 cubic metres (700,000 barrels per day), about 1998.

To support the offshore activities a number of marine vessels will be required, as shown in Figure 3.3-29. These are shown by delivery schedule and type of vessel.

A description of the vessel types is given in section 5.1.

Figure 3.3-30 illustrates the projected total tonnes of supplies required in the Beaufort Sea-Mackenzie Delta Region during each year of oil production. Also shown in the figure are the relative percentages of freight volumes by major commodity type. It can be seen that fuel will make up a large proportion of freight to be shipped, however, options such as building a topping plant or refinery in the north in order to reduce fuel transport are being investigated.

Figure 3.3-31 illustrates the estimated personnel requirements in the region by type of activity. This shows the number of people working on site at any one time, as opposed to the total number of people required to operate all shifts. The significance of these personnel requirements is addressed in Volume 5, Socio-Economic Effects.

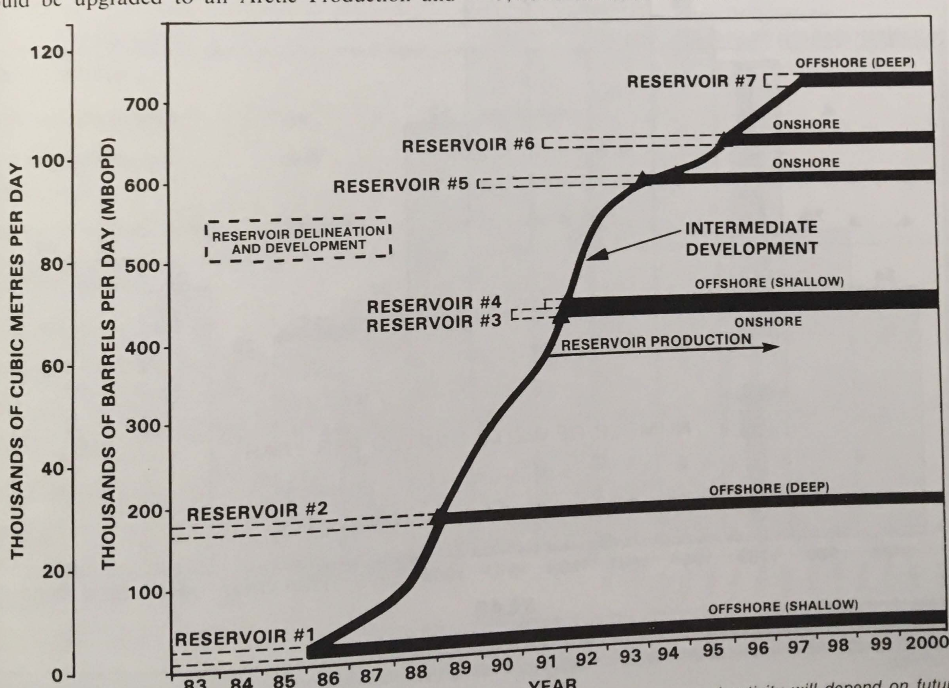


FIGURE 3.3-25 *The years 1987-2000 are much more difficult to forecast. The levels of activity will depend on future discoveries and the pace at which these discoveries are developed.*

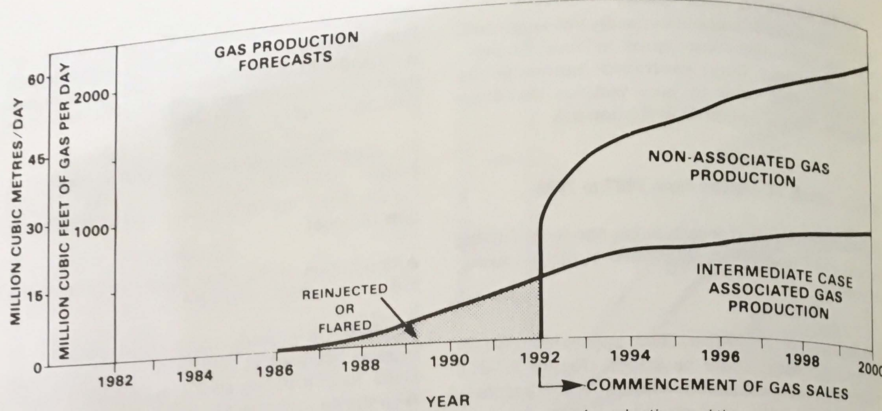


FIGURE 3.3-26 *Gas produced with the oil will be flared for the first year or so of production and then re-injected until such time as a transportation system to carry the gas out of the Beaufort Region is in place. When the transportation system is in place gas discoveries in the Beaufort (non-associated gas) will also be developed.*

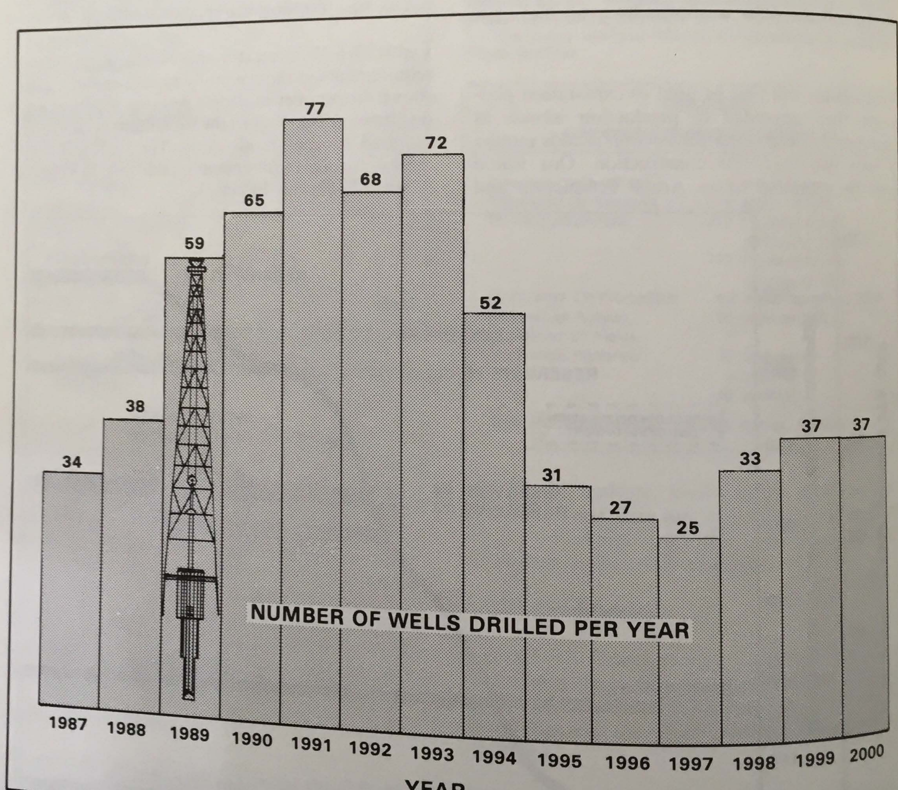


FIGURE 3.3-27 *An estimate of the number of wells drilled per year assuming the intermediate oil production rate is illustrated.*

PRODUCTION RATE	PROJECTED NO. OF EXPLORATION ISLANDS CONSTRUCTED PER YEAR																		
	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	2000
HIGH TECHNICALLY ACHIEVABLE RATE	2	1		1	1	1	3	3		3	3	3		4	4	4	4	4	4
INTERMEDIATE RATE	2	1		1	1		1			1		1		1		1		1	
LOWEST ECONOMICALLY VIABLE RATE	2	1		1	1		1			1		1		1		1		1	

PRODUCTION RATE	PROJECTED NO. OF PRODUCTION ISLANDS CONSTRUCTED PER YEAR																		
	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	2000
HIGH TECHNICALLY ACHIEVABLE RATE				1	1	2	2	4	2	3	4	3	2	3	1	1	2		
INTERMEDIATE RATE				1	1	1	2	2	2	4	4	2	1	1	1	1		2	
LOWEST ECONOMICALLY VIABLE RATE				1	1	1		1	1	2	2	2	1		1			1	

FIGURE 3.3-28 *The projected number of offshore exploration and production islands required for various production rates. Blank years are assumed to be bad ice years, when no islands can be built.*

VESSEL TYPE	SIZE	87	88	89	90	91	92	93	94	95	96	97	98	99	00
SMALL VESSELS															
ICE BREAKERS CLASS 10	150m X 30m										▲				
ICE BREAKERS CLASS 4	100 m × 22 m	▲	▲	▲											
SUPPLY BOATS	80 m × 18 m	▲	▲	▲	▲	▲	▲	▲	▲	▲	▲	▲	▲	▲	▲
ACCOMMODATION BARGE	150 m × 30 m	▲	▲	▲		▲	▲			▲		▲		▲	
MEDIUM VESSELS															
DRILLING BARGE	150 m × 30 m	▲	▲	▲		▲	▲			▲		▲		▲	
CONICAL DRILLING UNIT	65 m × 65 m	▲	▲		▲										
DREDGE	210 m × 35 m	▲	▲												
LARGE VESSELS															
PROCESS BARGE	200 m × 60 m	▲	▲		▲	▲	▲		▲			▲			
STORAGE BARGE	300 m × 70 m		▲		▲	▲	▲		▲			▲			
ARCTIC CRUDE CARRIERS	370 m × 50 m	▲	▲	▲	▲	▲	▲	▲	▲		▲	▲	▲		▲
VESSELS PRIOR TO 1987 (85)															
TOTAL NUMBER OF VESSELS		94	115	122	127	145	153	156	159	169	167	194	176	181	183

FIGURE 3.3-29 *Projected numbers of marine vessels delivered between 1987 and 2000 are illustrated (Intermediate Production Rate, Marine case).*

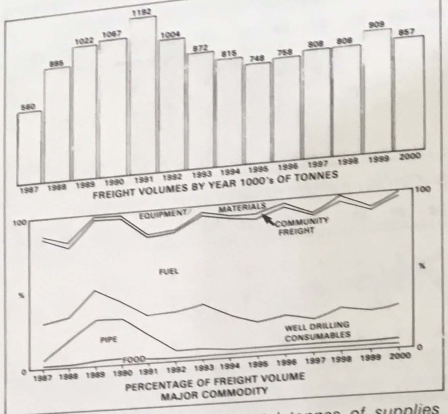


FIGURE 3.3-30 *The projected total tonnes of supplies required in the Beaufort Sea-Mackenzie Delta Region for each year of oil production are illustrated. The relative percentages of freight by type are also shown.*

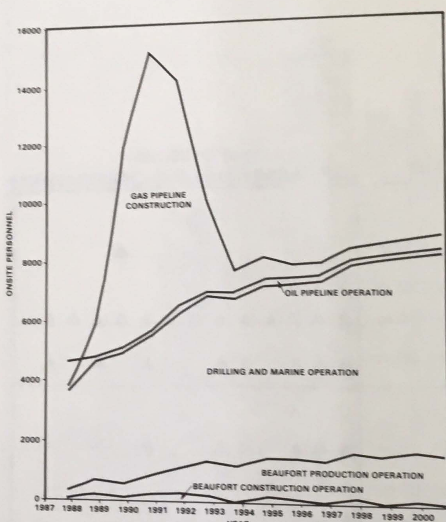


FIGURE 3.3-31 *The projected onsite personnel directly employed by the industry by activity type is illustrated.*

3.4 VARIATIONS IN DEVELOPMENT PLAN

An intermediate production development plan has been presented. However, this plan could be altered by a variety of factors. Some possible variations to the plan are discussed here.

3.4.1 CHANGE IN RATE OF DEVELOPMENT

There are a variety of factors which could cause a change in the rate of development from that projected. First, it might be found that oil reserves are smaller than was expected or, alternatively that they are much larger. If reserves are smaller, then oil production would be lower and this might slow the pace of development. If larger than expected commercial reserves are proven then oil production could be increased. Secondly, it is possible that the time required for construction of some major components may have been underestimated and thus certain activities may be delayed. Thirdly, regulatory approvals must be obtained before any development can proceed. The timing of these, regulatory approvals could thus affect the rate of development.

3.4.2 EARLY PRODUCTION

Oil production from the Beaufort Sea could begin in 1986 if an early production system were used. Such a system, illustrated in Figure 3.4-1 and shown in actual operation in Plate 3.4-1, does not require the construction of a large loading facility at an artificial production island. The major advantage of this type of system is that it allows the earliest possible date for oil production and allows time for more precise

PLATE 3.4-1 *An Early Production System is a crude oil processing and handling system which allows the earliest possible delivery of oil before the permanent production system comes on line. Subject to approval a similar system using an ice-reinforced tanker could be used in the Beaufort as early as 1986.*

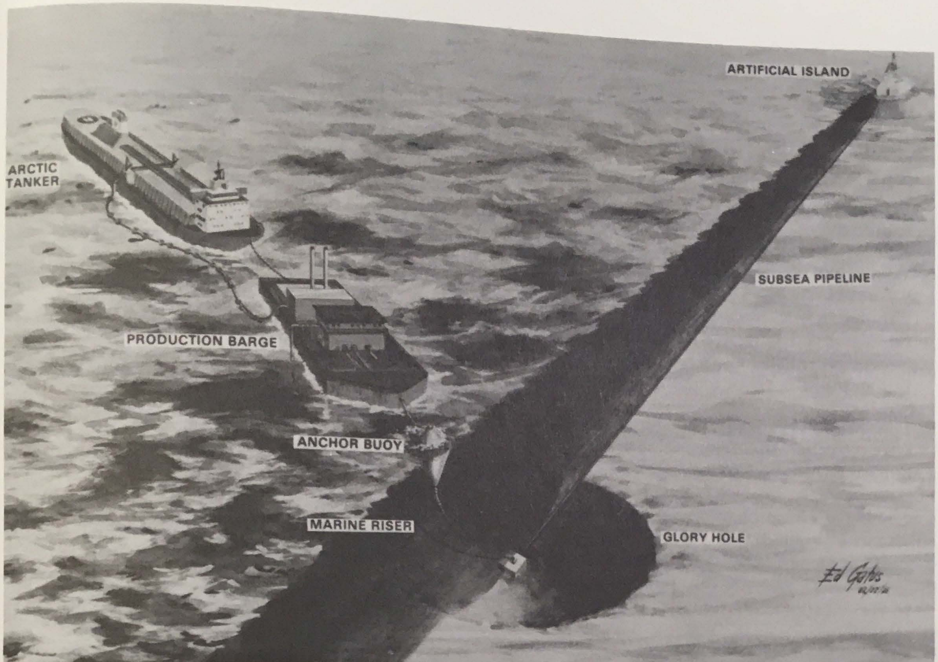


FIGURE 3.4-1 *An early production system could be used to enable production to commence while construction of the permanent facilities is underway. These systems are common around the world where three of four years are required to construct the permanent facilities. The early production system includes a floating production treating and storage facility connected to a producing artificial island by a seafloor pipeline. A tanker would load from the storage barge. The system would be an open water system in the Beaufort.*

reservoir information to be gathered before large financial commitments are made leading to full scale production.

This type of facility could be combined with a production island upgraded from an exploration island. It could also be moved to a new location if desired. Thus, once the first reservoir is connected to the permanent production system, the early production system could be moved to another reservoir.

3.4.3 TRANSPORTATION SYSTEMS

The alternatives, pipelines and tankers, are described in Chapter 6. Delivery of Beaufort Sea oil could start as early as 1986 using a tanker transportation system and 1987 using a pipeline. The ultimate decision to use either pipelines, Arctic tankers or a combination of systems will be based upon a number of considerations, including, for example, environmental and socio-economic impacts, project economics and crude oil reserves.

3.4.4 OTHER ARCTIC PROJECTS

Apart from the Beaufort Sea-Mackenzie Delta oil and gas development, there are a number of major projects currently being developed or planned to take place in the Arctic.

- Government approval has been granted for expansion of the Norman Wells oilfield in the Mackenzie Valley and the construction of a pipeline to connect it to southern markets.

- The Arctic Pilot Project is a proposal to produce gas on Melville Island and transport it to market by tankers operating year-round through the Northwest Passage.

- The Alaska Highway Pipeline Project proposes to transport gas from the Prudhoe Bay oilfield in Alaska, through western Canada.

- A Dempster Lateral Pipeline has been proposed to carry gas from the Beaufort Sea-Mackenzie Delta Region through the Yukon to connect with the Alaska Highway Pipeline.

- The Polar Gas project is a proposal to produce gas in the High Arctic Islands and transport it to southern Canada by pipeline. Part of their proposal is to have a branch line to receive gas from the Beaufort Sea-Mackenzie Delta Region.

- Mining projects are underway on northern Baffin Island and Little Cornwallis Island and the mineral potential of the Arctic makes it likely that further projects will be undertaken.

- The Prudhoe Bay oil field on the North Slope of Alaska has been in production since 1977 with oil transported by pipeline to Valdez in the south.

The timing and location of these projects may affect development in the Beaufort Sea-Mackenzie Delta Region. For example, construction of another Arctic project concurrent with this development could result in competition for supplies, services, personnel and transportation capacity. It might then be necessary to change the scheduling of activities and thus alter the development plan.

3.5 LEVELS OF ACTIVITY

The development planning process has just been described. There are many factors which affect the rate of development in the Region and these include, but are not limited to, the number of discoveries, the recoverable reserves, economics, and government policies. Another significant factor which affects the production rate and hence the level of activity in the region at a given point in time is the method of transport of hydrocarbons from the Region to southern markets.

Since it is difficult to predict with any degree of certainty the eventual production rate to be achieved in the Beaufort Sea-Mackenzie Delta, the Beaufort Planning Model (Section 3.2.8) was used to generate numbers which characterize the levels of activity for various rates of production. These numbers provide a range of activity levels from the so-called high technically achievable rate of oil production down to the so-called lowest economically viable rate of oil production. It is very likely that the actual rate of development will fall within this range of numbers. In this section these estimated activity levels are presented. They were also used in Volumes 4 and 5 to assist with the assessments of environmental and socio-economic impacts which will accompany development.

3.5.1 CRUDE OIL PRODUCTION

The projected crude oil production profiles expected to generate the various levels of activity are shown in Figure 3.5-1.

The following basic assumptions were used in the computer model to determine the level of activity resulting from each production rate.

1. For example, for the high technically achievable rate, there are nine deepwater discoveries, four shallow water discoveries and three onshore oil discoveries which will be placed on production by the year 2000. The oil fields in deep water are in a deep horizon (deep wells required) whereas three of the shallow water oil fields are shallow well horizons and the fourth is in a medium well horizon.

2. After a discovery is made, delineation drilling commences the following year. A minimum of two successful delineation wells are drilled per oil field before a commitment is made to initiate production. Construction of shallow water production islands will be completed two years after delineation drilling is completed. In deep water, three years are required to complete construction of the first island.

3. To develop the deep water discoveries, two artificial islands are constructed per field. The number of shallow water islands required for the development varies with the location. When an oil field is discovered from an artificial island, the exploration island may be expanded to become a production island.

4. In any offshore oil field, construction of the first production island is completed one year prior to production from that field. In shallow water locations, subsequent islands will be completed at the rate of one per year. In the model it is assumed that it will take two to three years to complete the second island at a deep water oil field.

5. Because of the dredging volumes required, only one deep water island could be completed in any year.

6. It is possible to exploit 95 million cubic metres of oil (approximately 600 million barrels) from each deep water island whereas each shallow water island can exploit 48 million cubic metres (approximately 300 million barrels). Three drilling rigs located on each deep water production island will drill nine wells per year. Production wells will be drilled on each shallow water island at the rate of 8 wells per year for shallow horizons and six wells per year for medium horizons, utilizing two drilling rigs per island.

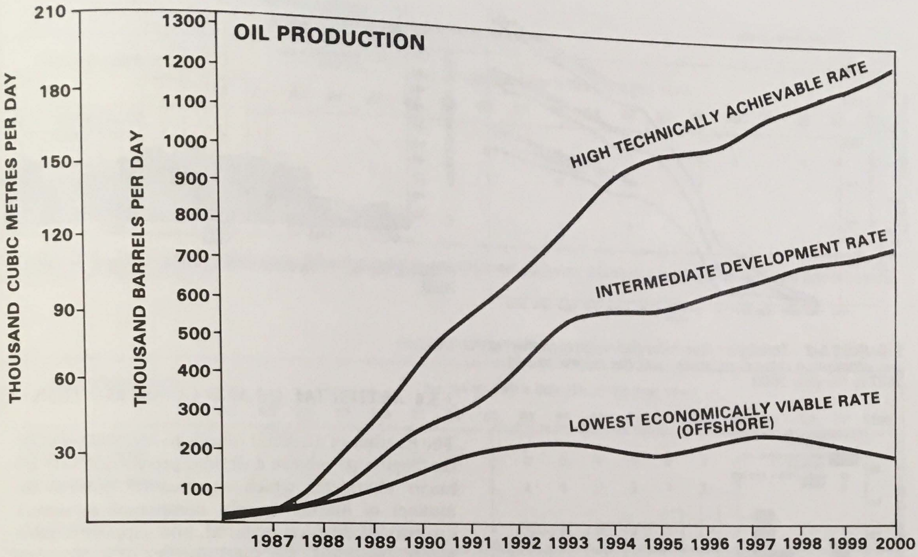


FIGURE 3.5-1 *A range of oil production rates can be achieved from the Beaufort Sea-Mackenzie Delta oil fields, depending mainly on the pace of development; high, intermediate, and low.*

7. One water injection well (included in the totals above) will be required per 2 producing wells. Injection commences two years after oil production in deep water oil fields. In shallow water, injection will commence the year following the initiation of crude oil production. Each oil field will have one gas injection well.

8. Each production island has primary production facilities (first stage separation), while each oil field has only one secondary production facility (described in Section 4.5).

3.5.2 GAS PRODUCTION

It has been assumed that the gas to oil ratio in an oil field development is 178 cubic metres of gas to one cubic metre of oil. (1,000 standard cubic feet of gas to 1 barrel of oil). Natural gas will be used as a fuel for production operations. Any excess gas will be flared during the first phase of oil production (about two years from each island for offshore locations) from oil fields which commence production before the gas can be moved to market. After two years, the gas will be injected into the producing formation until a gas transport system is in place.

Once a natural gas transportation system is completed, non-associated gas fields will be developed. Production from these gas fields and associated gas will probably be transported by pipeline though other means, such as LNG or methanol tankers might also be used.

Figure 3.5-2 shows the total gas production rates for the three development rates.

3.5.3 EXPLORATORY OPERATIONS AND PRODUCTION DRILLING

Exploration wells, or wildcats, are drilled both onshore and offshore in the Region on structures identified by seismic or other geological information. Delineation wells are drilled to provide more subsurface information on the discoveries and to determine if commercial reserves exist. The number of production wells drilled per structure (which includes injection wells) will be a function of many oil reservoir properties.

Figures 3.5-3, 3.5-4, 3.5-5 and 3.5-6 shows the range of drilling activity in the Region for exploration drilling, delineation drilling, production drilling and total wells drilled. The maximum and minimum number of wells drilled in any one year are provided to show the range in the levels of drilling activity considering the three production profiles.

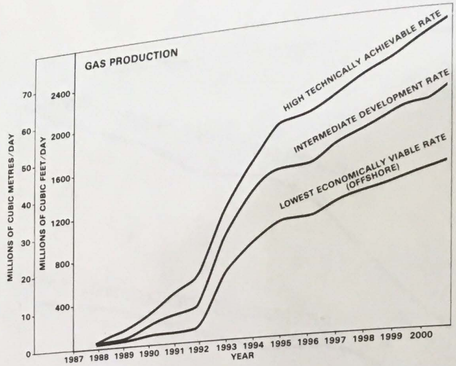


FIGURE 3.5-2 *This figure illustrates the range of projected gas production rates considered over the review period — 1987 to the year 2000.*

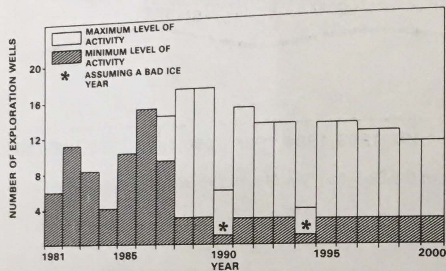


FIGURE 3.5-3 *Projected number of exploration wells — 1981 to 2000.*

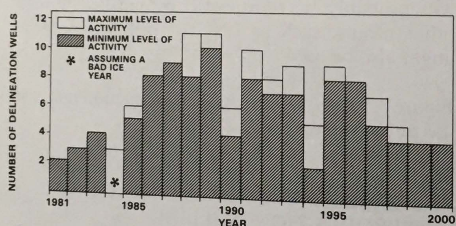


FIGURE 3.5-4 *Projected number of delineation wells — 1981 to 2000.*

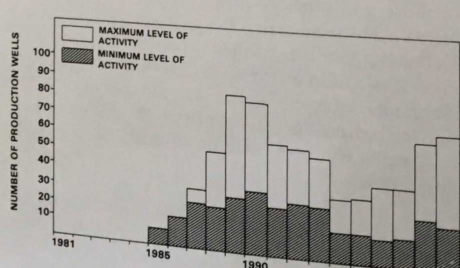


FIGURE 3.5-5 *Projected number of production wells — 1985 to 2000.*

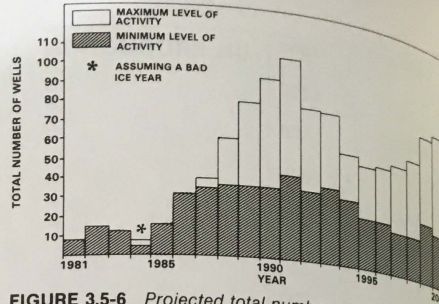


FIGURE 3.5-6 *Projected total number of wells — 1981 to 2000.*

3.5.4 ARTIFICIAL ISLAND CONSTRUCTION

The number of artificial islands to be constructed in the Region to achieve a desired production rate is a major parameter which significantly governs the number of marine vessels, number of personnel, quantity of dredged material, and support requirements. Naturally, the total number of exploration and production islands to be built in the Beaufort Sea is greatest for the highest technically achievable rate and lowest for the lowest economically viable rate (offshore). Figures 3.5-7 and 3.5-8 show the range in the number of exploration and production islands projected to be built to the year 2000 for these two cases.

As shown in the figures, the exploration island construction program for the highest technically achievable rate and the lowest economically viable rate (offshore) are similar up to 1985, then the level of activity for the highest production rate increases and is sustained throughout the forecast period. Exploration activities for the lowest rate continues to 2000, but at a much slower rate.

Production island construction for the two development rates proceeds in similar fashion up to 1989. From that year to 2000, additional production islands are required to put new fields on line for the highest development rate, whereas, only minimal activity is required to sustain the lowest rate.

Two Arctic Production and Loading Atolls (APLA) are required for the highest technically achievable rate, and a single APLA is required for the loading of Arctic tankers for the intermediate development rate. For the pipeline options, the crude oil produced offshore will be pumped to a northern pipeline terminal through subsea pipelines.

EXPLORATION ISLANDS

PRODUCTION RATE	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	2000
	No. OF ISLANDS CONSTRUCTED PER YEAR																		
HIGH TECHNICALLY ACHIEVABLE RATE	2	1		1	1	1	3	3		3	3	3		4	4	4	4	4	4
INTERMEDIATE RATE	2	1		1	1		1			1		1		1		1		1	
LOWEST ECONOMICALLY VIABLE RATE	2	1		1	1		1			1		1		1		1		1	

FIGURE 3.5-7 *Projected number of exploration islands constructed per year. Blank years are assumed to be bad ice years, which may or may not occur.*

PRODUCTION ISLANDS

PRODUCTION RATE	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	2000
	No. OF ISLANDS CONSTRUCTED PER YEAR																		
HIGH TECHNICALLY ACHIEVABLE RATE				1	1	2	2	4	2	3	4	3	2	3	1	1	2		
INTERMEDIATE RATE				1	1	1	2	2	2	4	4	2	1	1	1	1		2	
LOWEST ECONOMICALLY VIABLE RATE				1	1	1		1	1	2	2	2	1		1			1	

FIGURE 3.5-8 *Projected number of production islands constructed per year.*

3.5.5 GATHERING PIPELINES

Crude oil and gas produced offshore will be pumped to transportation terminals via subsea pipelines (Section 4.6). Similarly, oil or gas produced from onshore fields will be transmitted by onshore gathering systems (Section 4.7). Figures 3.5-9 and 3.5-10 show the maximum and minimum distance of offshore and onshore gathering pipelines in any year considering all of the development options.

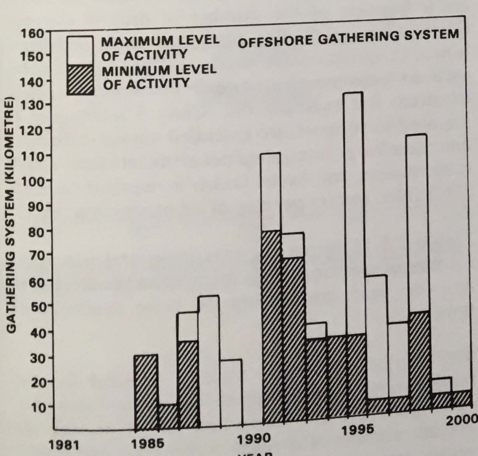


FIGURE 3.5-9 *Length of offshore gathering pipe projected to be installed in the Beaufort Sea.*

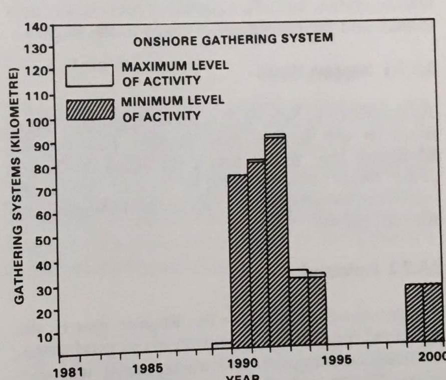


FIGURE 3.5-10 *Length of onshore gathering pipe projected to be installed in the Mackenzie Delta.*

3.5.6 DREDGING REQUIREMENTS

The dredging requirements for the offshore development are substantial, in that dredging of millions of cubic metres of sand is required for the construction of artificial islands and several hundred kilometres of trenches in the seafloor are required prior to installation of subsea pipelines. Figure 3.5.11 shows the maximum and minimum quantity of dredged mater-

ial required in the region in any one year considering all of the development options. Also shown are the dredging requirements for the intermediate level of production.

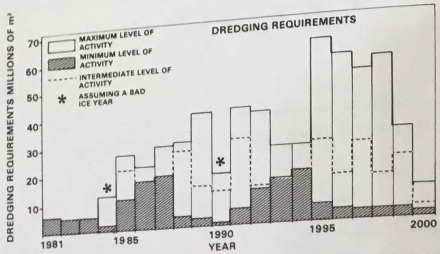


FIGURE 3.5-11 *Projected yearly dredging requirements during the period 1981 to 2000.*

3.5.7 SUPPORT REQUIREMENTS

Each major component of the development described earlier in this chapter requires significant support activity. These support requirements include marine vessels, aircraft, regional support bases, personnel, and the movement of cargo to the Region.

3.5.7.1 Support Bases

As described in Section 5.3, major regional support bases in the Region may include Tuktoyaktuk, McKinley Bay, Inuvik and a site along the Yukon coast. Other minor staging areas, fuel depots and construction camps will be required throughout the forecast period.

3.5.7.2 Personnel

The personnel required in the Region; that is, the personnel required for exploration and production, construction, support, and management will vary seasonally. As well, the personnel required and the job skills required for the various development options are considerably different. For example, the construction of an overland oil pipeline will require thousands of pipeline construction personnel. Figure 3.5-12 shows the range of personnel required to the year 2000, as predicted using the computer model for the highest and lowest production rates, and the number of personnel required per year for the construction of a 900 millimetre oil pipeline.

Figure 3.5-12 includes only those personnel who are in the western Arctic at any one time. This includes personnel working and those off shift. The personnel rotation system to southern Canada, which is two weeks in the Arctic followed by two weeks leave for most year-round positions, substantially increases the total personnel required. To estimate the total

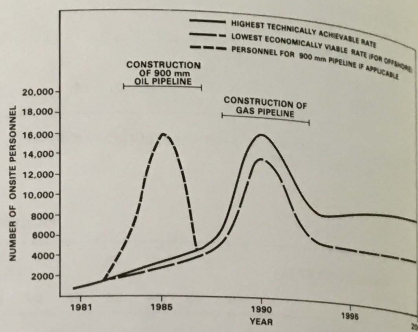


FIGURE 3.5-12 *Projected number of onsite personnel required for development activities. Peak manpower requirements occur during the construction of pipelines.*

personnel employed by the oil industry for Beaufort Sea-Mackenzie Delta Development, the personnel in the region shown in Figure 3.5-12 are multiplied by a rotation factor of 1.5 in 1984, 1.6 in 1985, 1.7 in 1986, 1.8 in 1980, 1.9 in 1989 and 2.0 between 1990 and the year 2000.

3.5.7.3 Marine Vessels

The number of marine vessels, including floating drilling systems, in the Region in any one year is a function of the level of activity. Supporting marine vessels such as support ships, icebreakers and tugs are a function of the number of drilling systems operating or production platforms under construction or in operation. Generally, a relationship can be used to estimate the number of support vessels required; for example one Class 3 icebreaker is required to support two extended season drillships, one crane barge is required per artificial island under construction, one Arctic tanker is required for each 8,000 cubic metres per day of oil production, etc.

Figure 3.5-13 shows the maximum and minimum number of marine vessels required in the Region in any one year, considering the three development options.

The number of Arctic tankers required for the marine transportation option is shown in Figure 3.5-14. Figures 3.5-15, 3.5-16 and 3.5-17 provide the average number of dredges, icebreakers and supply vessels, respectively, which are required in the Region.

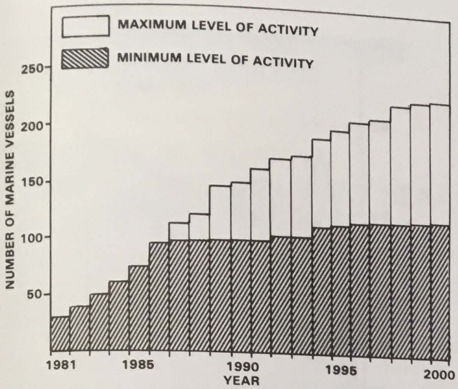


FIGURE 3.5-13 *Projected number of marine vessels required during the period 1981 to 2000.*

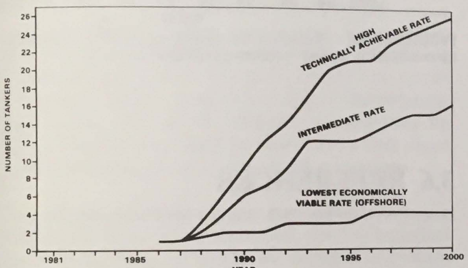


FIGURE 3.5-14 *Projected number of tankers required to transport oil during the period 1981 to 2000. This projection assumes that no pipelines are used.*

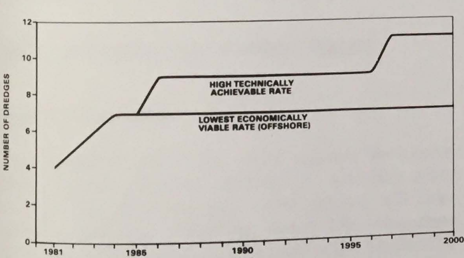


FIGURE 3.5-15 *Projected number of dredges required to build offshore facilities during the period 1981 to 2000.*

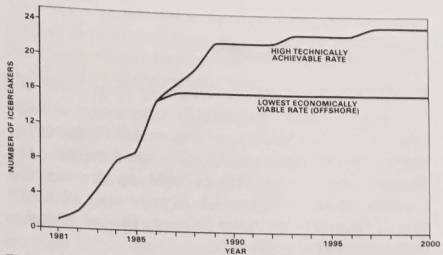


FIGURE 3.5-16 *Projected number of icebreakers required during the period 1981 to 2000.*

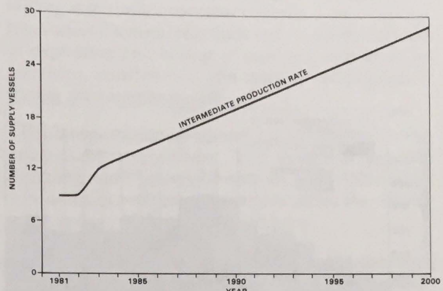


FIGURE 3.5-17 *Projected number of supply vessels required during the period 1981 to 2000.*

3.5.7.4 Aircraft Support

Long range aircraft are required to transport personnel, perishables, and some emergency cargo to the region. Regional aircraft including helicopters and STOL aircraft are then required to distribute the personnel and cargo from the major support bases to the Region. Regional aircraft including helicopters Figure 3.5-18 shows an estimate of the projected aircraft requirements by year.

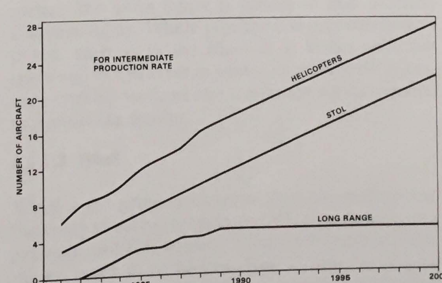


FIGURE 3.5-18 *Projected number of aircraft required during the period 1981 to 2000.*

3.5.7.5 Freight Movements

Freight is moved into the Region by barge down the Mackenzie River, by sea lift operations around Alaska, by road and by air. Figure 3.5-19 shows the maximum and minimum freight requirements in the Region each year to 2000, considering all projected production rates. Figure 3.5-20 provides a distribution of freight movements by mode for the intermediate development plan.

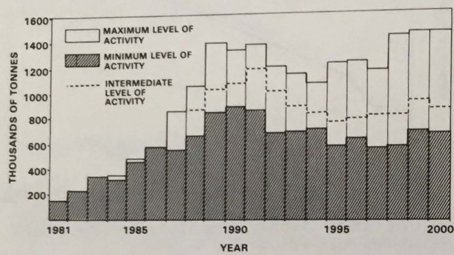


FIGURE 3.5-19 *Projected quantity of freight to be transported to the Region per year during the period 1981 to 2000.*

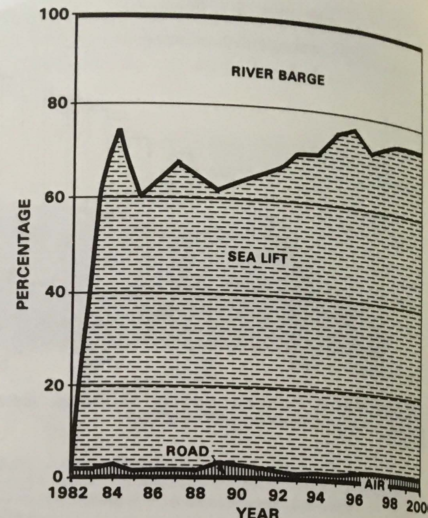


FIGURE 3.5-20 *Projected distribution of freight movements by mode for the intermediate development plan.*

3.6 REFERENCES

Dome Petroleum Ltd. 1982. Beaufort Sea Planning Model.

CHAPTER 4
BEAUFORT SEA - MACKENZIE DELTA DEVELOPMENT SYSTEMS

4.1 PHYSICAL FACTORS AFFECTING BEAUFORT SEA-MACKENZIE DELTA DEVELOPMENT

Physical factors profoundly affect the manner in which development and operations can be conducted in the Arctic. Some of the more important physical factors that affect development are illustrated in Figure 4.1-1. Further information and references are provided in Volumes 3A, 3B and 3C. Due to the severe climate and remoteness from centres of population and manufacturing, the narrow climatic windows available for transportation become very important. As an example, the season for the west coast sea lift is extremely short, and in some years vessels may not have sufficient time to return around Point Barrow to the Pacific as the polar ice pack may drift into coastal waters. Also, the retreat of the polar ice pack at the start of the shipping season may be delayed by adverse winds; in such years a very short open water season occurs for sealift operations.

The effects of climate and remoteness together require extensive lead times and careful logistical planning in order to carry out planned activities. Whereas construction materials, methods and scheduling in the Beaufort Sea-Mackenzie Delta may vary significantly from southern Canada, construction and operation of facilities in the Arctic are well within the realm of available technology.

4.1.1 ATMOSPHERIC ENVIRONMENT

4.1.1.1 Temperature

Low temperatures in the Arctic hamper the execution of most activities. Most of the activities associated with this proposed development will take place in an area extending about 250 kilometres north from Inuvik, which is located in the Mackenzie Delta about 200 kilometres north of the Arctic Circle. Here the mean January temperature is about -32°C and the mean temperature remains below freezing for eight months of the year. Over the Beaufort Sea the average January temperature is below -25°C and the average July temperature is about 5°C. In addition, even light winds can produce a wind chill which lowers the effective temperature. As an example, with winds of 32 kilometres per hour a temperature of -32°C becomes effectively -64°C.

To counter these cold temperatures workers must be protected and insulated as much as possible. Work in the open is slower and less efficient and as much work as possible must be accomplished in heated shelters.

The low temperatures also increase maintenance and operating problems with equipment and vehicles and necessitate the use of special materials and methods. For example, during the development of the Alaskan North Slope oil fields, steels suffered brittle failures at below normal stresses; welding techniques had to account for extremely rapid cooling, with consequent changes in the metallurgical properties of the materials used; and the rapid freezing of materials containing water was a constant concern. Low temperatures affect chemical reactions such as the detonation of explosives and curing of concrete, and in some instances, construction can only be accomplished during the summer months.

The transportation of oil and gas by pipeline is also affected by temperature. The design of pipeline pumping and compressor stations must account for low ambient temperatures, which affect the density and viscosity of fluids being pumped.

Humidity declines with temperature and hence very low temperatures result in a very low relative humidity. Due to static electricity in this dry air, aircraft refueling is a greater hazard in the far north.

4.1.1.2 Precipitation

The Region receives little precipitation and some Arctic areas are referred to as "polar desert." For the colder months, Inuvik receives less than 2.5 centimetres per month of rainfall or equivalent snowfall. During July, August and October this may rise to 5.0 centimetres per month. Total annual precipitation decreases steadily as one proceeds northwards. Thus, on the Tuktoyaktuk Peninsula the design snow-load is 0.92 kiloNewtons per square metre, while at Fort Good Hope further south in the Mackenzie Valley the design snow-load is 2.88 kiloNewtons per square metre. The latter figure is similar to that in many southern areas. Where pipeline construction is proposed, such as in the Mackenzie Valley,sufficient snow will be available in winter to provide the necessary working surfaces and temporary roads required to protect the tundra.

4.1.1.3 Wind

Wind is the primary cause of pack ice motion and thus may affect navigation and offshore drilling. For example, in 1974, westerly winds in the summer held the ice pack near the shoreline; in other years east winds have driven the pack ice seaward and provided open water from Point Barrow to Banks Island. Winds, therefore, largely determine whether it will be a good ice year or a bad ice year.

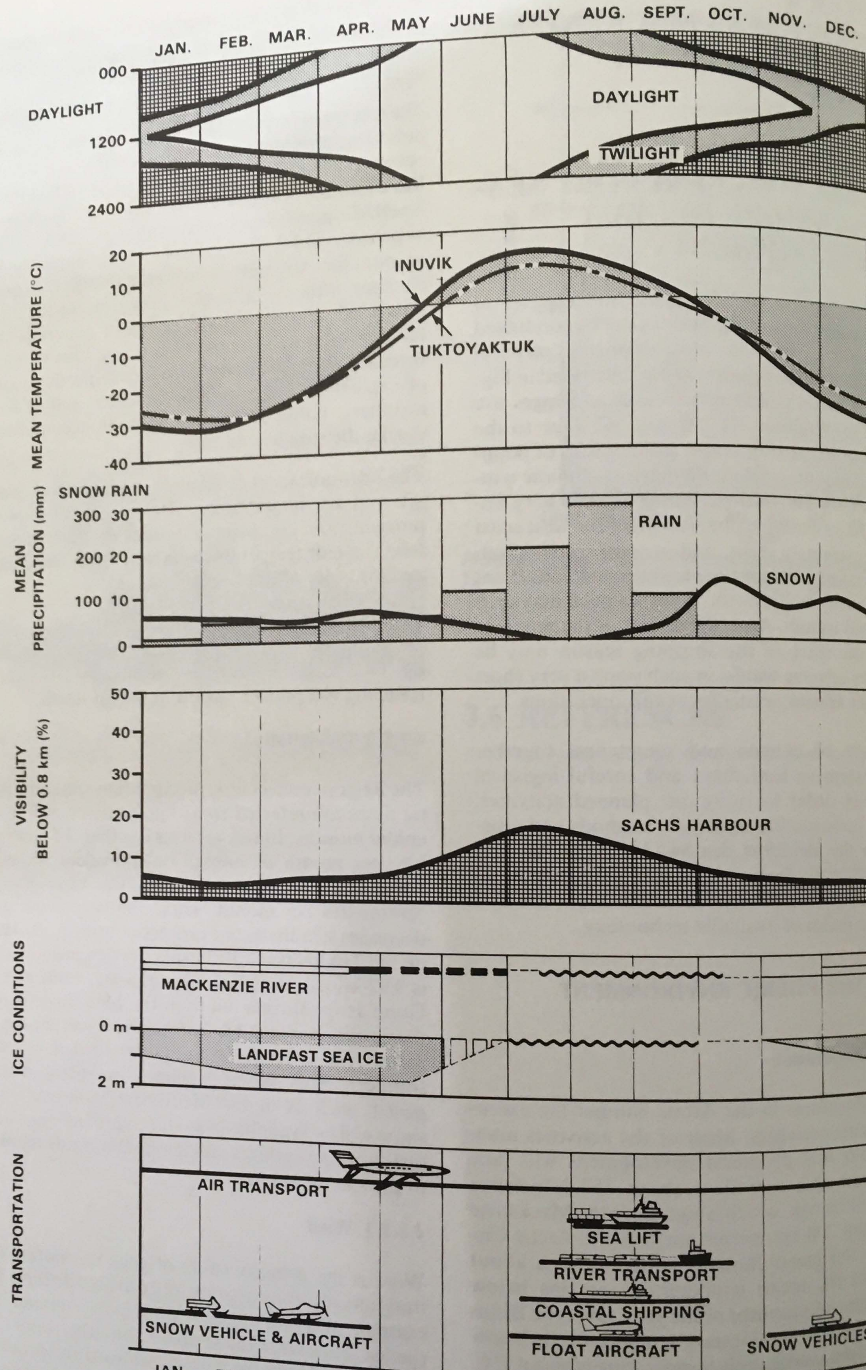


FIGURE 4.1-1 *The above physical factors affect development. The Beaufort Sea-Mackenzie Delta Region is characterized by 24 hour daylight during the spring and summer months to near 24 hour darkness throughout the winter. The average temperatures vary from about minus 35 degrees C in the winter to plus 15 degrees C in the summer with extremes of minus 45 degrees to plus 30 degrees. The area is relatively dry in winter and summer.*

The greatest impact of the local wind pattern will be felt by the transportation sector of the proposed activities. All marine transportation must continually respond to wind conditions and sea states, particularly shallow draft vessels operating in coastal waters. Also, air transport, particularly regional and local flying operations using relatively light aircraft, are affected by adverse wind conditions.

4.1.1.4 Visibility

Reduced visibility may cause inconvenience and schedule disruption, though it does not usually severely hamper operations on the ground. In general, visibility in the Arctic is good with local conditions at specific sites sometimes requiring special consideration.

White-outs are a particularly severe weather condition in which visibility is minimal and no differentiation can be made between the earth's surface and the sky. This may be caused by low overcast cloud, diffused light, blowing snow, fog, or similar circumstances.

Reduced visibility due to fog occurs most often in the summer. However, ice fog also sometimes occurs. Air operations can be brought to a temporary halt while the fog persists, which may be from one hour to a number of days.

4.1.1.5 Daylight

In the Arctic, for a period in summer the sun remains above the horizon 24 hours a day, while in winter it remains dark 24 hours a day. For example, at Inuvik on the Mackenzie Delta in November it is dark for about 13 hours a day and twilight for the remaining 11 hours. During December, the sun does not rise at all and does not reappear again until mid-January. Sunlight then returns for progressively longer periods each day, and by May there is continuous daylight for about three months. These long hours of sunlight in the summer are an advantage to Arctic operations, however, in winter illumination must be provided for all activities 24 hours per day.

4.1.2 ICE ENVIRONMENT

4.1.2.1 Ice Zones

There are three principal ice zones in the Beaufort Sea; the landfast, transition and polar pack zones. These ice zones are illustrated in Figure 4.1-2 which is a cross-section of typical ice features from the shore to the polar pack ice zone.

Landfast ice is anchored to the shoreline or to the sea bottom and is more or less stationary. This ice grows out from the shore each year to approximately the 20 metre water depth contour by mid-February. All of the artificial islands constructed in the Beaufort Sea prior to 1981 have been located in the landfast ice zone. In the southern Beaufort Sea, this ice is seldom more than one year old, forming in the fall and building to a thickness of 1.5 to 2 metres throughout the winter and then melting in the spring and summer. Newly formed sea ice may move a few kilometres per day in late autumn and early winter. However, once the ice becomes landfast, movement is in the order of metres per day.

The polar pack consists of multi-year ice 3 to 4 metres thick with old pressure ridges which may reach 50 metres in thickness. Hummock fields are formed by extensive ridging in the multi-year ice along the western edge of the High Arctic islands. These fields may be hundreds to thousands of metres across and 10 to 15 metres thick. The pack is not a rigid ice surface, as is demonstrated by the rubble fields within it, and the continual opening and closing of numerous leads which may be hundreds of kilometres long. The polar pack ice drifts in a clockwise direction under the influence of winds, gravity and ocean currents. This motion is called the Beaufort Gyre and has an average peripheral movement of 3 kilometres per day.

The zone between the moving polar pack and the stationary landfast ice is known as the transition zone. The width of this zone varies from year to year due to northerly and southerly shifts of the polar pack. Some years the zone may be up to 320 kilometres wide while in other years it can be 50 kilometres or less. The transition zone is generally composed of first-year or seasonal ice which forms in early October and exists until June or July. Because of the dynamic conditions that exist in this zone, the ice is subjected to large natural forces which cause many pressure ridges and rubble fields to form. Oil and gas prospects extend offshore into this region. The Tarsiut artificial island, constructed in 1981 in 22 metres of water, is located in the transition zone. Plate 4.1-1 shows the transition zone in January 1982 near the Tarsiut island.

4.1.2.2 Pressure Ridges

Pressure ridges are formed as a result of a structural failure of level ice which has been subjected to horizontal forces. The forces that contribute to this failure are wind, currents, and the moving polar pack. The longer these forces are applied the larger the resulting ridge will be. Many experiments have been conducted with pressure ridges during the last several years.The pressure ridge is now not the obstacle to marine navigation that it was believed to be a few years ago.

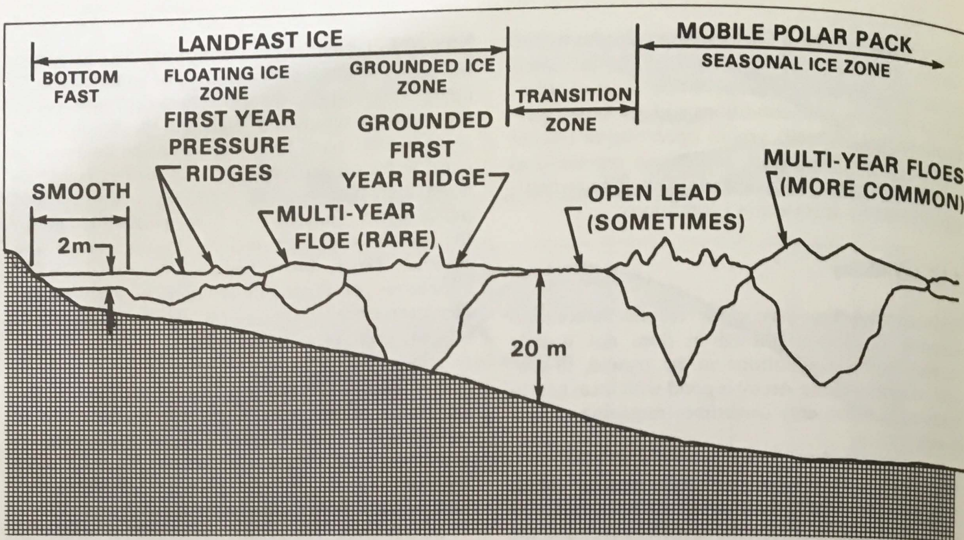


FIGURE 4.1-2 *There are three ice zones in the Beaufort Sea. Landfast ice includes new ice which forms in the fall of the year and is anchored to the shore line. By the end of the winter, the landfast ice extends out to where the water depth is about 20 metres. Further to the north and west is the polar pack which is multi-year ice that exists permanently and is constantly moving in a clockwise direction under the influence of gravity, ocean currents and winds. The polar pack retreats to the northwest in the summer and encroaches on the southern Beaufort Sea in the winter. The area between the landfast ice and the polar pack is the transition zone. During the winter it is characterized by numerous ice features such as pressure ridges and rubble fields.*

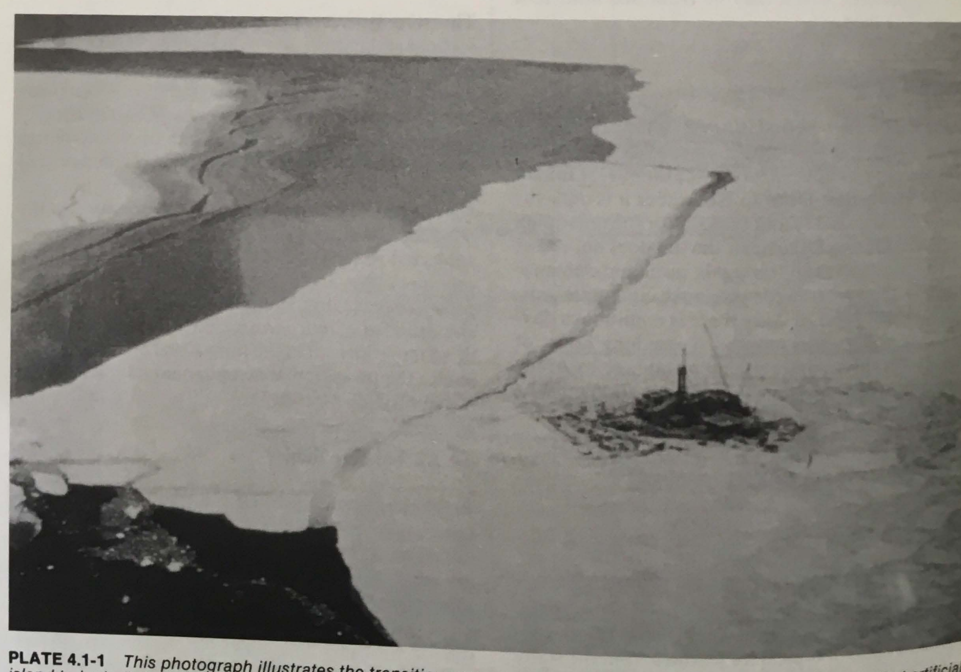


PLATE 4.1-1 *This photograph illustrates the transition zone near the Tarsiut island. The Tarsiut island is the first artificial island to be built in the moving ice zone.*

4.1.2.3 Rubble Fields

The term rubble field has been applied to describe the mass of failed ice generated by the passage of moving ice around on artificial island. The area of the rubble field may cover several square kilometres.

The rubble fields are more difficult to traverse with an icebreaker than pressure ridges because they are wider and are somewhat plastic. Multi-year rubble fields are even more difficult to traverse because of their width and overall size.

4.1.2.4 Ice Islands

Ice islands are large ice features up to 60 metres thick and several kilometres across which calve from the ice shelves of Ellesmere Island in the High Arctic. They may enter the Beaufort Gyre and move with the pack ice. These features present the most formidable obstacle to navigation and permanent structures due to their large mass. Fortunately, ice islands are very rare and the probability of interaction between an ice island and a structure in the development area is very low.

4.1.3 MARINE ENVIRONMENT

4.1.3.1 Bathymetry

The Beaufort Sea has three main physiographic features:

- the continental shelf extending to the 100 metre isobath;

- the continental slope; and

- the deep Canada basin beyond the 3,000 metre isobath.

The Beaufort Sea is bisected by the Mackenzie Canyon which extends from the Delta out to the 500 metre isobath. East of the canyon (north of the Tuktoyaktuk Peninsula) the continental shelf is typically about 160 kilometres wide while west of the canyon the shelf is about 80 kilometres wide. Also, the continental slope is less steep on the east side of the Mackenzie Canyon. A submarine delta exists east of the canyon and the near-shore waters are extremely shallow, with water depths of less than 10 metres as far seaward as 35 kilometres off Richards Island and the Tuktoyaktuk Peninsula.

Permafrost, pingo-like features and ice scours are of importance to navigation and offshore drilling in the Mackenzie Delta and Tuktoyaktuk Peninsula areas. Permafrost exists at some depth below the ocean floor. In addition, pingos are found under water and take the form of ice-cored conical submarine mounds 300 metres in diameter at their base and sometimes rising to within 15 metres of the surface. Ice scours, furrows in the seafloor, are found between the 15 and 45 metre isobaths. These features must be considered in designing structures and locating pipelines for these areas.

4.1.3.2 Oceanography

Storm surges are common on the Beaufort Sea coast during the ice free months of August, September and October. These occur when a low pressure area passes from west to east along the coast accompanied by onshore northwesterly winds and increased river runoff. At Tuktoyaktuk, 22 surges were recorded in an 11 year period. The highest recorded surges had heights of 2 metres and 3 metres. Negative storm surges, resulting in lowered sea levels along the coast, may be caused by passage of a high pressure system and strong easterly winds, but these are rare.

Beaufort Sea oceanography is of importance to many development activities. For example, negative storm surges may cause ships to ground in shallow harbours while positive surges can cause damage to shore installations unless considered in design criteria. The amplitude of surges decreases offshore and thus they are of little importance to offshore facilities. However, wave characteristics are important in designing offshore structures to resist applied loads, although ice pressures replace the wave forces in controlling some aspects of design. The structure of the continental shelf and water movements also result in current and ice patterns which effect exploratory operations and the construction and maintenance of permanent islands.

4.1.3.3 Seismicity

Preliminary assessments of seismic sources and seismicity in the Beaufort Sea Region have revealed that several areas within the Region have recorded seismic activity.This activity has been centred in three areas: the Richardson Mountains, Martin Point and the Beaufort Sea Seismicity Cluster (located about 200 kilometres offshore in water depths of 200 to 2,000 metres). Seismic activity in the Martin Point area has been in the range of 1 to 5 on the Richter Scale. Recorded events in the Beaufort Sea Cluster have ranged in magnitude up to 6 on the Richter Scale over a wide area.

Figure 4.1-3 shows the location of faults and earthquake epicentres in the area of oil and gas development. Between the Beaufort Sea Seismicity Cluster and Tuktoyaktuk, lies the Kaltag Fault Zone. Tuktoyaktuk itself is located on the northwestern edge of the Eskimo Lakes Fault which extends up the Tuktoyaktuk Peninsula. Minor epicentres have been

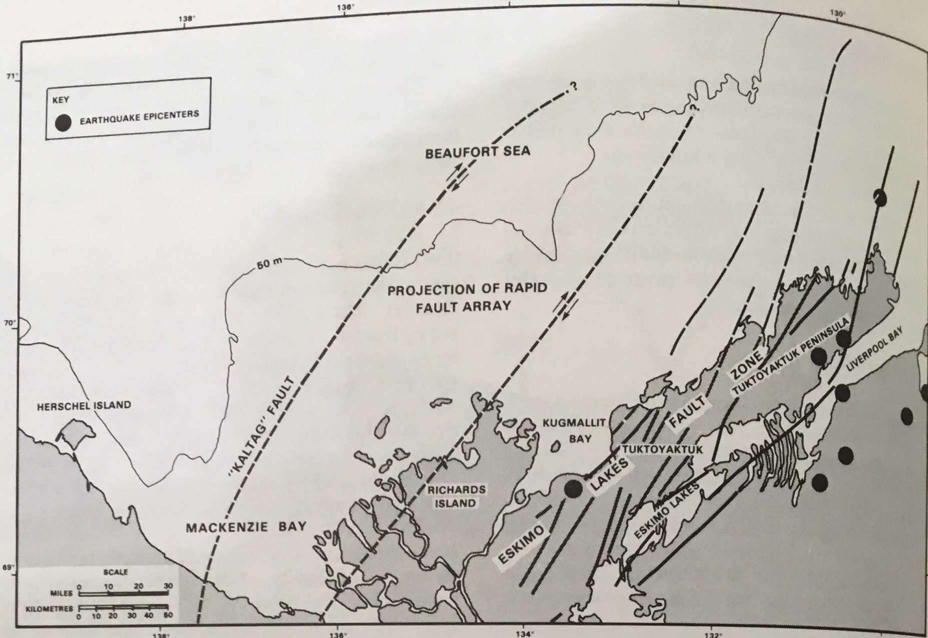


FIGURE 4.1-3 *Minor seismic activity (earthquakes) have been recorded throughout the Beaufort Sea Region. Seismic forces are not expected to have a major impact on permanent Beaufort Sea structures. Nevertheless, a program is in place to monitor seismic activity and incorporate seismic forces in the design of structures.*

located to the south of this fault zone, however none have been located under the Beaufort Sea in the area of drilling or proposed island construction.

4.1.4 TERRESTRIAL ENVIRONMENT

4.1.4.1 Terrain Features

The Mackenzie Delta and Tuktoyaktuk Peninsula are basically flat with numerous lakes and channels. In addition to other problems, these numerous bodies of water prevent land transportation during the spring and summer months which leads to logistical problems for overland supply. The exception, of course, is the Mackenzie River itself which becomes a transportation artery during the summer.

Flooding occurs in the Delta areas as a result of spring runoff. The water level rises about 1 metre in the middle parts of the Delta causing widespread flooding of the alluvial islands. Storms can also result in flooding of low-lying areas onshore.

4.1.4.2 Permafrost

Permafrost is permanently frozen soil which occurs both on land and on the continental shelf under the Beaufort Sea. East and west of the Delta, the ground is frozen to a depth of about 600 metres. However, in the Delta itself, permafrost only extends to depths of 20 to 60 metres. During the summer the surface of the ground thaws to a 0.3 to 0.6 metre depth before refreezing; this is known as the active layer. In the continuous zone, permafrost exists everywhere except under lakes and river channels, while in the discontinuous zone, there are only local lenses of permafrost.

All onshore production facilities would be situated within the continuous permafrost zone. A pipeline to southern Canada would pass from the continuous zone into the discontinuous zone about 300 kilometres south of the coast.

Relic permafrost, a result of land subsidence, exists 30 to 100 metres below the seafloor, and could extend to a depth of 600 metres. This land possessed a permafrost layer which has never completely thawed after being submerged under the sea.

Permafrost does not present a problem to development in areas where rock predominates. However, if foundations must be supported on clay or sand material that are ice-rich, then the permafrost could pose some problems. If any form of heat is applied to the ice-rich material, the ice content turns into water.

the material softens and the foundations could settle. The permafrost must be prevented from melting either by placing large granular pads over the ground and then constructing roads and structures on these insulating pads (see Section 4.3) or by raising the structures above ground level by constructing them on piles. Pipelines may also have to be elevated to prevent the heat of the oil from melting the permafrost (see Section 6.2).

Methods of coping with permafrost under the ocean are not as elaborate as on land since the artificial islands used result in low bearing pressure at the seafloor. Assuming adequate insulation from surface structures, the only source of heat that could cause melting of subsurface permafrost is that generated in the producing well bores by the warm oil flowing to the surface. The thawing and subsidence of the frozen layer is a major factor in the design of well casing and foundations in Arctic operations.

Studies are now underway to predict the behaviour of permafrost soils under specific conditions (See Volume 7). These studies include computer modelling of single wells and clusters of wells and an analysis of the effect of potential permafrost casing failure on well integrity. However, the likelihood of settlement is minimal, since wells will be completed with low thermal conductivity packer fluid located between two casings in the annulus, which will effectively retard thawing of the permafrost. Other more elaborate techniques could also be employed, such as the addition of insulation around the casings. If settlement did nonetheless begin to occur, artificial freezing of the soil could be undertaken in a similar way to that used for many years to stabilize civil engineering excavations.

4.1.4.4 Tundra

The land surface in this region is characterized by a shallow layer of topsoil covered with lichen, moss and peat. This cover protects and insulates the permafrost underneath, keeping it frozen. If the tundra is damaged or removed, for example, by the passage of vehicles and machinery, then localized thawing, water runoff and erosion take place. This degradation of the tundra can gradually spread and so must be avoided. Typically gravel is placed over the tundra to provide roads and development pads. The object is to keep the tundra frozen even in summer. In winter adequate snow cover must be ensured before proceeding with activities on the tundra. The use of correct development techniques and procedures will minimize any harmful effects to the tundra.

4.2 FUNDAMENTALS OF OIL AND GAS EXPLORATION AND DEVELOPMENT

This section describes the fundamentals of exploration and production of oil and gas fields, beginning with an account of conventional oil and gas field operations already in existence in the older producing areas of Canada and the United States. It then describes the variations from conventional procedures that must be used in the Arctic, both on land and offshore.

4.2.1 THE EXPLORATION PHASE

The exploration phase involves collecting and analyzing seismic information to determine the character of the underground strata, followed by test drilling to determine if promising subsurface structures contain oil or gas in commercial quantities.

4.2.1.1 Seismic Surveys

Seismic surveys can generally define with considerable accuracy the shape of rock formations hundreds of metres below the land or water surface. Under certain circumstances, it is possible to estimate the type of fluids contained in suitable reservoir rock. However, seismic surveys cannot determine whether oil and gas exist in commercial quantities. This can only be determined by drilling exploratory wells.

Seismic surveys involve initiating a shock wave at the surface, detecting each reflected wave, and recording the time that it takes the shock wave to travel from the surface to some reflective layer beneath the surface and back to the shock wave receiver. The time lapse between the creation of the energy wave and the detection of each reflected wave gives an indication of the depth and slope of the boundaries between rock formations. A series of these measurements, over a wide area, enables geologists to draw maps which, in effect, define the 'topography' of various subsurface strata.

The basic equipment used in conducting a seismic survey consists of a source of energy or shock waves, geophones (microphones) to detect the reflected waves, and a recording apparatus. The process of creating a wave and of detecting and recording the reflections is repeated at different points along a straight line, and then the whole procedure is repeated along a number of parallel lines. The distance between the lines and between the points at which the shock waves are created, is determined by the level of detail that is needed. Wide spacing is

adequate for the initial surveys, with the distances becoming smaller as more is learned about an area and more detail is required. The seismic survey system is illustrated in Figure 4.2-1.

When the subsurface maps are completed, the geologist searches for 'traps', which are locations beneath the surface where the migration of oil through the rocks may have been stopped. This results in an accumulation of oil or gas. One example of such a trap is called an anticline, as shown in Figure 4.2-2. Oil or gas moving through porous rock could be trapped beneath the dome of non-porous rock. If the resulting reservoir were large enough, commercial oil or gas may be the result.

A key element in conducting a successful seismic survey is the creation of a strong energy wave. On land this is usually done by drilling a shallow hole and setting off an explosive charge in the hole. The "shot hole," as it is commonly known, is used so that more of the energy is directed downward. Offshore, explosive charges are no longer used and the energy wave is created with a sounding apparatus such as an air-gun. The shock waves generated by an explosion under water may kill nearby fish, whereas the waves generated by air-guns or similar devices do not injure fish or marine mammals (see Volume 4 for further discussion).

In the Mackenzie Delta-Beaufort Sea Region, seismic surveys on land are only conducted when the ground surface is frozen (late October to early May). This reduces the impact of the activity on the sensitive surface covering. The equipment is mounted on tracked or similar all-terrain vehicles. The typical seismic crew consists of 20 to 30 persons including surveyors, geophysicists, shot hole drillers, explosives handlers and assistants. The operation consists of surveying the shot hole and geophone locations, drilling the hole, placing the explosive charge in the hole, and setting out the geophones. Once the equipment is in place, the recording apparatus is activated and the explosive charge is detonated. The equipment is then moved along to the next location.

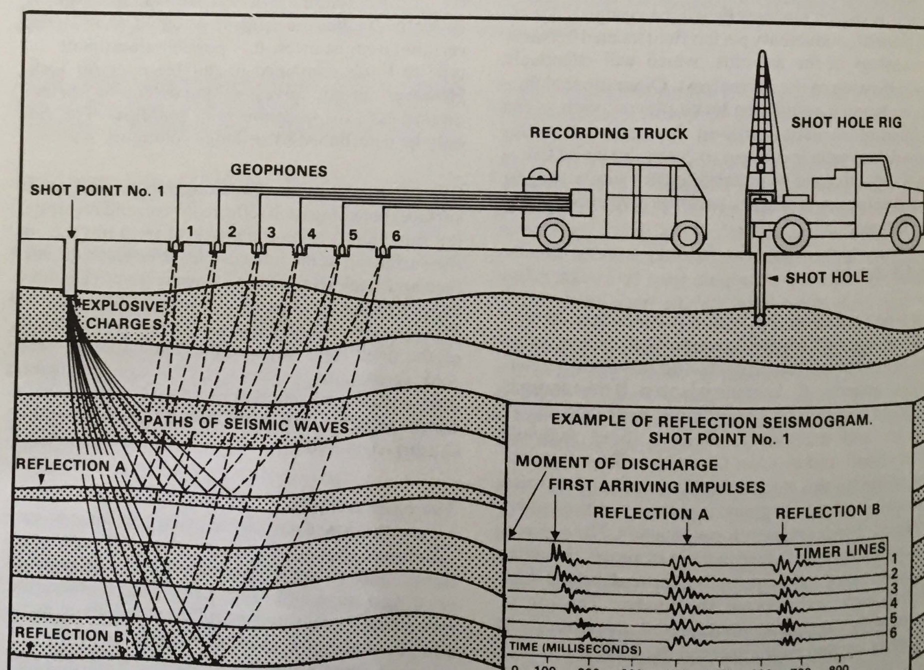


FIGURE 4.2-1 *The equipment used to obtain seismic information include a source of energy, geophones and a recording apparatus. On land, shot holes are drilled and explosive charges are set off in the shot hole. The geophones measure the length of time a reflected energy wave reaches the surface. These data, in the form of a seismogram, are used to define the subsurface strata.*

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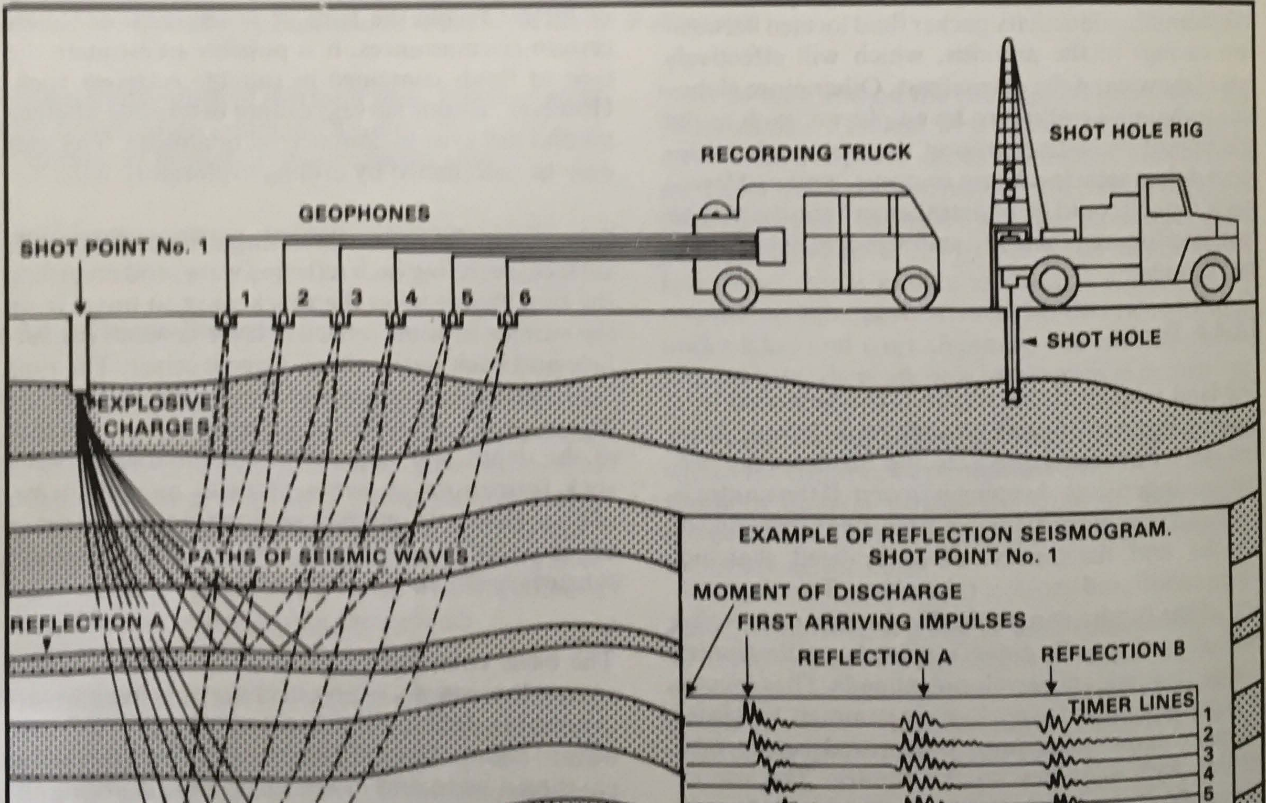

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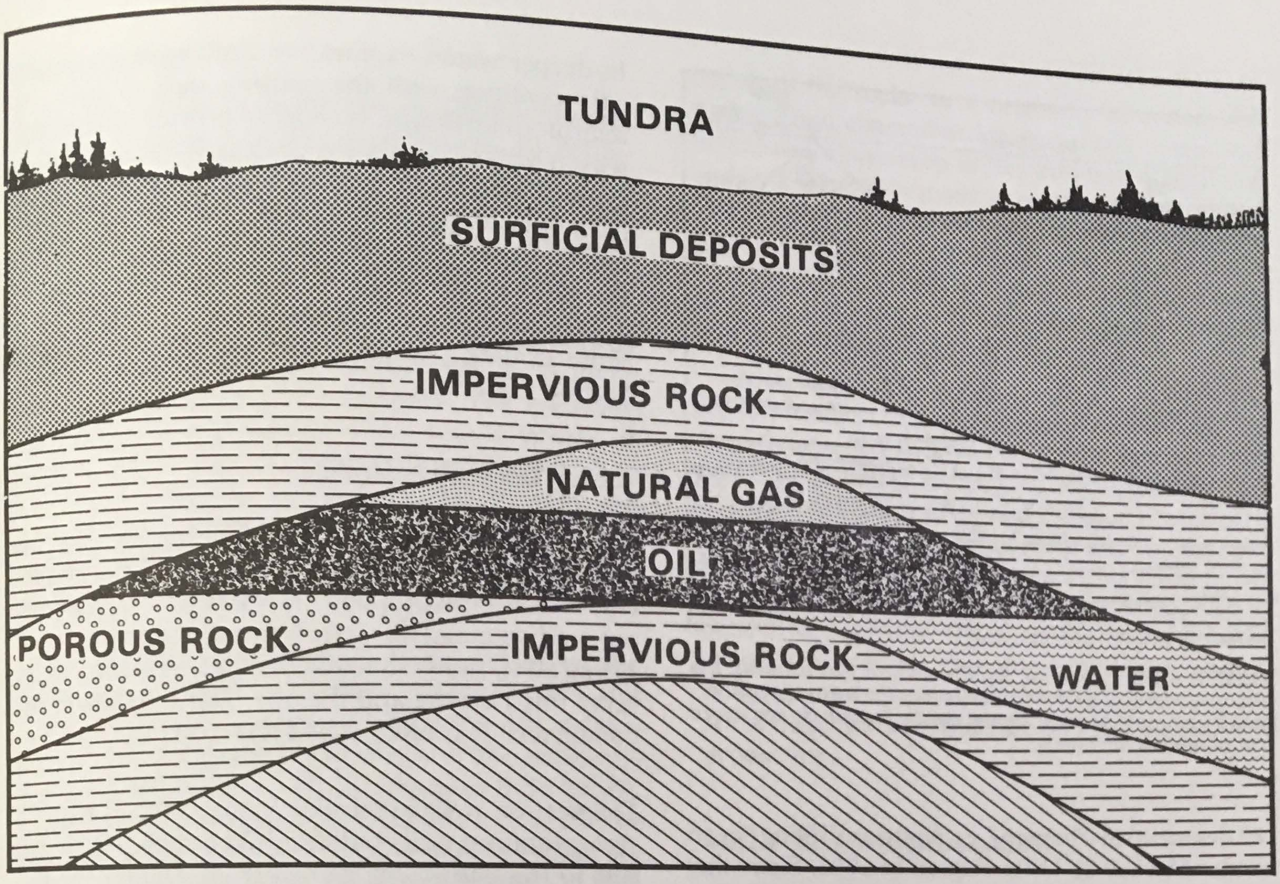

FIGURE 4.2-2 *Oil is formed from the partial decomposition of organic matter. After millions of years, the oil migrates through sedimentary rock until it reaches a place where it is trapped. An anticline, as shown in this figure, is an example of a trap where oil migration may be stopped causing the accumulation of oil or gas.*

In the Beaufort Sea, seismic surveys are conducted during the open water season using specially designed ships. These ships are equipped with the apparatus to create the shock waves, to record the reflected waves, and to process and analyze the recorded information. The ship also contains living quarters for the personnel. In conducting an offshore survey the reflected energy waves are picked up by microphones spaced along a cable that is towed behind the ship (Figure 4.2-3). Since all the equipment needed to conduct a seismic survey is carried on one ship and since the ship is highly mobile, an area can be surveyed much faster than is the case on land. Seismic surveys have also been conducted from the ice surface in much the same way as done on land; however surveys conducted from ships are more efficient.

In the Beaufort Sea-Mackenzie Delta Region, future seismic programs will be more site specific and aimed at providing a better definition of reservoir geometry. Principal activities will be running tie-in lines to verify the correlation between exploratory wells and previous seismic maps, closer grid surveys, and 3-dimensional seismic surveys over discoveries or highly promising structures.

Seismic surveys have many other uses in the Region. Shallow surveys, which are undertaken using the same equipment but with different energy sources, have applications in identifying shallow high pressure water zones (see Section 4.4.6.2), defining permafrost zones for route selection of subsea pipelines, defining the sea bottom sediment at artificial island construction sites, and locating subsea sources of sand and gravel for island building.

4.2.1.2 Exploration Drilling

Information gained by exploratory drilling will clarify, and may prove or disprove, the geologist's interpretation of data gathered through seismic surveys. As drilling progresses, the geologist studies drill cuttings recovered from the well, in addition to cores which are obtained by special drilling techniques. Experience indicates that only one well in ten finds oil and one well in fifty finds a commercial field. However, it is common for a great number of unsuccessful exploratory wells to be drilled in a new basin and then after the first discovery, several additional discoveries may follow quickly as the data from the successful well unlocks the mystery of the new area.

The drilling of 'wildcat' exploratory wells takes drillers to a variety of places since the subsurface usually has little relationship to the surface. In many places, for example the United States, exploration can continue for seventy or eighty years after the first oil is discovered.

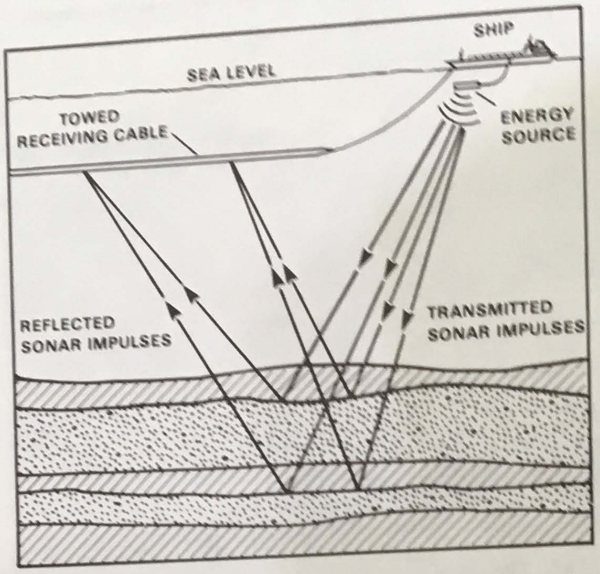

FIGURE 4.2-3 *Offshore, explosives are not used as the energy source for seismic surveys. Energy waves are generated by air guns or other similar devices which do not injure fish or marine mammals.*

As described in Chapter 2, exploration drilling began in the Mackenzie Delta Region in 1965. Since that time about 100 wells have been drilled onshore. The industry moved offshore in 1973, and drilling from islands has moved into progressively deeper water. To date exploration drilling has been conducted from nineteen artificial islands built in the Beaufort Sea in water depths up to 22 metres. Deep water drilling began in 1976 from ice-reinforced drillships. Today, 15 wells have been drilled from floating vessels in water depths ranging from 23 to 68 metres. Drilling systems and procedures used in the Beaufort Sea-Mackenzie Delta Region are described in detail in Section 4.4.

On land, exploratory drilling takes place on gravel pads designed on a site specific basis to prevent permafrost thaw and to provide a structural base for the drilling equipment. Since the science of drilling in the Arctic tundra is well developed, little change in the type and arrangement is expected during the forecast period.

In shallow water offshore (usually considered as the area in water up to 20 metres deep), artificial islands provide the platform for drilling systems. Island building technology has developed significantly since 1976 and will continue to be refined as more experience is gained. Caissons, such as those used at the Tarsiut island, permit steeper side slopes of the earthen berm, and hence less dredged material, and are able to withstand ice and wave action. These reuseable caissons, and deeper steel or concrete caissons will be used in shallow water and will play a bigger role in the exploration of prospects in 18 to 30 metres of water.

In deeper water, exploration drilling will undoubtedly continue with the existing fleet of four ice-reinforced drillships. In order to provide an extended season drilling capability, designs of floating drilling systems which can withstand the ice-related forces have been developed. These units, having an ice-breaking profile and huge mooring systems to anchor the ships to the seafloor, will provide exploratory drilling in most ice conditions. The onshore and offshore drilling platforms are described in detail in Section 4.3.

4.2.1.3 Delineation Drilling

When a wildcat well becomes a discovery well it is necessary to determine the magnitude of the discovery, both in terms of size of the reservoir (reserves present) and potential flow rate for production purposes. Delineation wells, sometimes called appraisal wells, serve this purpose and thereby help to confirm the commercial feasibility of the reservoir.

Delineation wells are drilled in an identical manner to exploration wells but are drilled more efficiently due to the knowledge gained from drilling the discovery well. Typically, in the North Sea 3 to 8 delineation wells were associated with each discovery well and a similar experience is likely to occur in the Beaufort Sea-Mackenzie Delta Region. However, the number of delineation wells drilled is determined by the geological structures present.

Delineation wells are located and drilled to depths which, when completed, will maximize the information obtained. Consequently, delineation wells, in addition to being drilled within the known reservoir structure, may be drilled off the known reservoir structure to determine the areal extent of the reservoir or to delineate possible aquifers which will provide energy for producing the oil. Also, they can be drilled above or below the expected producing formation to define the extent of the oil in the discovered or related structures.

Upon completion of the delineation well drilling program, information is then available to determine the potential for commercial development of the reservoir.

4.2.2 OIL AND GAS RESERVOIRS

Knowledge of reservoir characteristics is essential to the planning for commercial development of oil and gas fields and their subsequent management. The evaluation of reservoir characteristics is described in this section.

4.2.2.1 Geology

The sands of most of the Mackenzie Delta structures were laid down in a deltaic environment. By definition this means that the depositional waters were relatively shallow, with the area of deposition being alternately covered by sea water and breaking above the sea level throughout the thousands of years that the deposition was taking place. These sands are technically known as 'turbidites' and were deposited during catastrophic type occurrences in geologic times such as floods and sandslides. The sands are therefore somewhat channel-like with a variety of grain size. The age of the rock is tertiary which is relatively young by geologic standards. Oil has migrated through the older sediments in the tertiary sands where it has been trapped by a combination of structure and imperious rock.

When the deltaic type sands were laid down the deposition channel was likely quite smooth and gently sloping in a seaward direction. At a later geologic time, however, the shape of the sediments was modified by tremendous pressures from below. The pressures resulted from thick sections of clay or shale which tended to extrude upward. The result is a series of hills and valleys which, in conjunction with the impervious rocks laid on top of the channel sands, created a favourable environment for hydrocarbon accumulation.

4.2.2.2 Rock Characteristics

Discovery wells provide the first real insight into rock characteristics. In the case of Kopanoar, the well was not 'cored' throughout the pay section and the rock samples that came to surface in the drilling mud were relatively small. Cores collected from the side of the hole along with data from electric and radioactive logs were used to determine the rock characteristics.

Rock characteristics important from an engineering point of view include porosity, which is the measurement of the void space between the grains of the rock, permeability, which is a measure of the ease with which fluids can move through the rock, and grain size and distribution, which are measures of homogeneity of the rock. These factors all affect the volume of oil that may be present in the rock, the ease with which it may be recovered, and have some bearing on the relative volume of recovery (recovery factor).

4.2.2.3 Fluid Characteristics

Pore space in the rock will always be filled with fluid: oil, water or gas. Most sediments contain salt water since oil and gas are formed in a marine environment. Thus when oil and gas are found, water is also present since the rocks were originally saturated with water. Fluid characteristics are generally unknown before wells have been drilled and tested. Well logs and rock samples provide some information on fluid characteristics and well testing (which is a procedure whereby well fluids or reservoir fluids are allowed to flow to surface). These also provide large samples of reservoir fluid and facilitate an accurate determination of fluid characteristics.

Of importance to reservoir determination are the proportions of the three fluids: oil, water and gas, and their chemical and physical characteristics. For example, data from Kopanoar indicate that the pores of the rock contain approximately 25% water and 75% oil, and that the oil has an API gravity of 37°, contains no sulphur and has a high proportion of light hydrocarbons. There is sufficient reservoir energy for properly completed producing wells to flow at a rate in excess of 2,000 cubic metres per day. All of these characteristics are very favourable for oil production.

4.2.2.4 Reserve Determination

To determine reserves one must first ascertain the total volume of oil existing in the reservoir (oil in place) and multiply this by the fraction of the oil in place that can be economically recovered (recovery factor). The volume of oil in place is typically determined volumetrically. One needs to know the thickness of the reservoir, the areal extent of the reservoir, the porosity of the rock and the fraction of the porosity that is occupied by oil. Another factor is the amount of gas that is dissolved within the oil, since this gas, when the pressure is released, causes the volume of oil to decrease as it comes to the surface.

Information from several wells is usually required to provide a reliable estimate of oil in place. Refinements to this number continue even after several hundred wells have been drilled.

The recovery factor depends on such things as reservoir energy, fluid and rock characteristics, reservoir management techniques and economics. Recovery factors generally range from 15% to 50%.

The term 'threshold reserve' is used to identify the lowest recoverable reserve that one could justify developing on a commercial basis. Development costs, production rates and prices are all important considerations. For a reserve to be economically viable, it is necessary to establish that reserves are equal to the threshold value. Projected threshold reserves in the Beaufort Sea-Mackenzie Delta Region have been discussed in Chapter 3.

4.2.3 RESERVOIR MANAGEMENT

Reservoir management refers to the procedure of developing and operating an oil or gas field. Proper reservoir management requires an understanding of geology, physics and chemistry. Good management of the reservoir is aimed at recovering the maximum amount of oil and gas under economic conditions. The following sections describe the factors affecting reservoir management. Reference is made to the Kopanoar field as an example of how a reservoir may be managed in the Beaufort Sea.

4.2.3.1 Reservoir Geometry

The configuration of the reservoir, that is, its shape, size, thickness, and rock characteristics, are key factors in the design of the reservoir management system. The geometry of the field helps design of the reservoir management system and helps determine how many wells are required and where the wells will be located. The geometry is particularly important in offshore fields because it determines how many production islands or platforms will be required to accommodate the directionally drilled producing wells.

For conventional onshore fields, reservoir geometry is less of a consideration, since wells are usually drilled vertically and surface development costs are not one of the major components of the overall development costs.

The depth of the reservoir in offshore fields is also a factor since it affects the 'reach' of the directionally drilled well. Since directionally drilled wells are initially vertical and then directed so that they deviate 60 degrees or more from the vertical, the deeper the well the greater the horizontal reach. Thus, very shallow reservoirs present more of a problem to the offshore operator than deeper reservoirs.

Figure 4.2-4 shows the geometry of the Kopanoar field and the location of the discovery well and first step-out well. If further delineation drilling verifies this interpretation then two production platforms or islands would be required. Multiple wells would be drilled directionally from each platform, based on the wells being uniformly spaced every 65 hectares in the reservoir.

4.2.3.2 Reservoir Energy

In order for oil to flow from a subsurface reservoir to the surface, energy must be applied to the reservoir. In almost all cases considerable 'natural' energy exists in the reservoir system. Oil usually contains dissolved natural gas. As long as the reservoir is held under pressure, the gas stays in solution. When the pressure is reduced, gas breaks out of solution and the energy of the expanding gas causes the fluid to move. In a great many cases there is sufficient reservoir pressure and gas dissolved in the oil to cause the oil to flow all the way to the surface. Sometimes the volume of gas present exceeds that which can remain dissolved in the oil so a free gas phase exists in the reservoir. Since gas is much lighter than oil, free gas will always rise to the top of the reservoir to form a 'gas cap.'

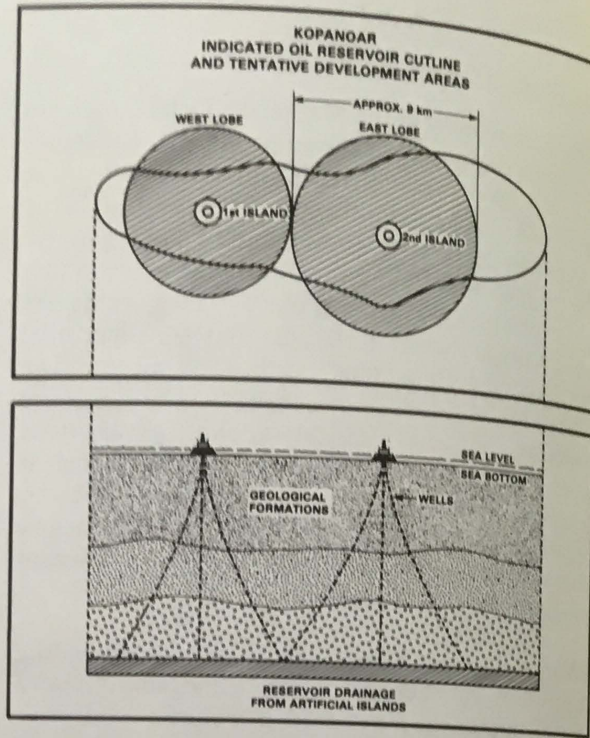

FIGURE 4.2-4 *This drawing illustrates the geometry of the Kopanoar oil field. The seismic data have proven to be very accurate in the Beaufort Sea so there is a high confidence level in the geologists predictions of subsurface structures.*

Initial pressure in a reservoir is usually at least equal to the weight of a column of water extending from the surface to the deepest part of the reservoir. Thus a reservoir at a depth of 3,000 metres would normally have a reservoir pressure of about 31,000 kPa. Wells drilled into the reservoir provide the opportunity to reduce the pressure at the wellbore face so that the oil will flow into the well and to the surface. When a gas cap exists the expansion of the gas cap is one form of energy that forces the oil from the reservoir into the wellbore. Another form of energy which commonly forces the oil from the reservoir into the wellbore is water. Water is usually present below the oil, under pressure. The volume of water is frequently hundreds of times larger than the volume of oil so that as oil is produced, water migrates into the reservoir to maintain pressure.

Thus, there are three types of 'drive' in a reservoir: solution gas drive, gas cap drive, and water drive. The nature of the natural drive is the key to the recovery factor. Recovery factors under natural drive could vary all the way from a few percent of the oil in place up to 40 or 50%. Rarely would it exceed 50%.

In modern oil field operations, natural reservoir energy is frequently supplemented with energy from other sources. In order to improve the recovery factor and the production rate from the reservoir, water is frequently injected into a series of water injection wells around the periphery of the field or interspaced among the producing wells. The injected water behaves exactly like a natural water drive; it moves through the reservoir in the direction of the producing wells, sweeping the oil ahead of it. One may also inject gas into an existing gas cap or perhaps inject gas into the top of the reservoir even though a gas cap may not exist. These techniques are frequently referred to as 'secondary recovery' since they are applied to supplement the natural energy. A field producing with primary energy alone might recover 20% of the oil in place. When a water flood is applied the recovery could be increased to 40%.

These recovery methods are sometimes supplemented with more exotic techniques such as steam, fire flooding or flooding with detergent type fluids. These techniques are usually aimed at recovering a portion of the 'residual' oil. Residual oil is that oil which is left after normal recovery. These techniques are called tertiary recovery and may recover another 10 to 20% of the oil in place. No system has yet been devised to recover 100% of the oil in a reservoir in an economical manner.

In the later stages of the producing life of an oilfield, a great deal of water may be produced with the oil. Sometimes there is not enough natural energy to cause the well fluids to flow to the surface. Thus, additional energy is frequently applied through the producing wells themselves in order to improve the rate at which the oil flows to the surface. This is called artificial lift.

One method of artificial lift is the injection of additional gas at various places in the producing tubing string. Injected gas expands in the same way as naturally dissolved gas and thus helps move the oil towards the surface. A second method is the use of mechanical pumping situated at the bottom of the well. Pumping systems, however, are not usually practical in offshore installations because the directionally drilled wells are not vertical, thus 'gas lift' is the system usually used offshore.

Prior to the drilling of a discovery well, it is not possible to ascertain the type and quality of reservoir energy that may be available. Testing of the first well provides the first insight and gives data on the amount of gas that is contained within the oil. Tests indicate whether or not a gas cap may be present, and it may indicate the presence of water below the oil. Additional wells help to define the energy regime.

4.2.3.3 Production Planning

In production planning, conservation considerations are integrated with economic factors so that the recovery of oil and gas is optimized and the cost of production is minimized. The principal factors that must be taken into consideration include the following:

- oil and gas in place
- recovery factor
- field geometry
- field depth
- surface constraints
- oil and gas prices
- transportation costs
- production costs
- royalties and taxes
- time to first production
- field life
- production
- development costs
- fluid characteristics
- conservation regulations
- rock characteristics

Two key parameters which must be assumed in designing a development plan for any oil field are the 'field life index' and the 'economic life of the field.' The 'field life index' is the ratio of the total reserves to the maximum producing rate, while the 'field life,' as the name implies, is the number of years over which

the economic production from the field will be recovered. These two factors are both related to field production rates and, when combined with reservoir geometry and producing characteristics, they determine how many wells will be required to develop an oil field.

For example, if the recoverable reserves of an oil field are 160 million cubic metres, a reasonable field life index would be 10. The production rate from this field would increase gradually to a maximum of 16 million cubic metres per year, or about 45 thousand cubic metres per day. The production level would remain at this rate for several years and then commence a decline as reservoir energy was depleted, or the water or gas that was sweeping the oil toward the producing wells broke into the wells and was produced with the oil. Less and less oil would be produced until the total production rate declined to a level where it was no longer economic to produce oil. A reasonable field life would extend over 20 to 30 years.

The number of wells and well spacing is dependent upon a number of reservoir parameters including depth, geometry, and permeability to fluid flow. For example, at Kopanoar the field area is approximately 100 square kilometres. Reasonable drainage of the reservoir could be expected with one well every 65 hectares, that is 160 wells. If half the wells were producing wells and half were injection wells, there would be 80 producers and 80 injectors. The 80 producers would collectively need to produce 45 thousand cubic metres per day which is about 650 cubic metres per day each. This requirement would be compared with the test information to determine if the wells are capable of this type of production. The discovery well flowed at a rate of over 1,000 cubic metres per day and the calculated potential exceeds 2,000 cubic metres per day. The 560 cubic metres per day average then should not be difficult to achieve. In fact, the maximum field production rate selected may be higher than 45 thousand cubic metres per day, thus giving a lower field life index and perhaps a lower field life, depending on the rate of decline.

At Kopanoar, a minimum of four delineation wells will be required to establish the field geometry with a reasonable degree of confidence. The time required to drill these wells is about two years.

Any development plan can be revised as new information becomes available through drilling of producing wells. Well spacing can be changed, well design can be changed, different producing rates can be accommodated, and so forth.

In the case of large oil fields like those expected in the Beaufort Sea, it is not necessary to define the entire field in order to justify proceeding with development. Only a certain area can be accessed from a given platform or island location. Thus, each platform or island can be analyzed on a project basis. At Kopanoar-type water depths, the threshold reserve to justify production is estimated to be about 80 million cubic metres. This would provide a production rate of about 22 thousand cubic metres per day and would require one island and about 80 wells (40 producers and 40 injectors). Thus the initial aim of the developers of Kopanoar is to demonstrate that 80 million cubic metres of oil are accessible from one location. The appraisal of the entire field will follow accordingly.

4.2.3.4 Reservoir Modelling

Reservoir modelling is a relatively new technique that has been made possible by the computer. It is employed to mathematically simulate an oil reservoir and predict its performance over its entire field life.

The three dimensional reservoir model simulates an oil reservoir by dividing it into thousands of little cubes each of which are assigned values for rock and fluid characteristics. Well established mathematical formulae describe the movement of fluids from one cube to another. The model keeps track of the flow of fluids through the reservoir to the producing well, the pressure in all cells of the model, the remaining saturation of oil, water and gas, and the producing rate. The quality of the model is improved as more data become available.

Reservoir modelling early in the development of a field is very useful even though quantitative data are sketchy. Since many of the variables are known early in the life of the field (particularly fluid and rock characteristics), the development plan can be made available at a much earlier stage than otherwise.

4.3 PLATFORMS FOR DRILLING AND PRODUCING SYSTEMS

Perhaps the biggest difference between the exploration and production phase of the oil industry is the degree of permanence of the facilities. Exploration facilities, either onshore or offshore, are temporary since no one wants to make a large capital outlay for facilities without knowing whether the exploration will yield favourable results. For example, in a southern Alberta exploration program, temporary roads

are built to the well site locations, drilling personnel live in trailer units, and all equipment is as mobile as possible. In an offshore exploratory program, wells are drilled from mobile rigs, tested and usually abandoned, while the rig moves on to explore elsewhere.

Production facilities are permanent since they must last the 20 to 30 year life of the oil or gas field. Durable roads are built, proper warehouses and accommodations are erected and production facilities are set on stable foundations and properly housed to suit the long-term environmental conditions. Offshore fields have been developed from steel or concrete platforms permanently anchored to the sea floor and producing to facilities that are designed to last for many years.

This section deals with the platforms that will be used for drilling and producing facilities in the onshore and offshore Beaufort Sea-Mackenzie Delta Region. These are the platforms or structures that will accommodate the drilling rigs which drill the exploration, delineation and production wells, and accommodate the relatively simple processing facilities that separate the oil, gas and water, or which support transportation systems.

This section also describes the design, construction and maintenance features of onshore and offshore platforms, with emphasis on the design criteria used to counteract the physical regime unique to the Region.

4.3.1 ONSHORE PLATFORMS FOR DRILLING AND PRODUCTION

In southern Canada, platforms for drilling rigs and all of their supporting equipment and platforms for production systems present few problems for conventional land drilling. Typically, a two to four hectare site is cleared and graded, and the drilling rig is positioned over the point where the well is to be drilled. The accessory equipment such as fuel tanks, water and mud tanks, mud pumps, mechanical and electrical power systems, accommodation for the crew, and storage systems are positioned around the rig at distances sufficient to provide safety and adequate working space.

The foundations for drilling systems and permanent production facilities are designed in a manner similar to other man-made structures in southern Canada. The foundations are usually relatively simple because the point loads are low, so special piling is not usually required.

The loads in the Arctic are similar to those in southern Canada. However, failure to prevent the thawing of the permafrost during operations will seriously reduce bearing strength, resulting in a potential for structural failure and unnecessary erosion. Thawing of the permafrost is prevented by construction during winter, by applying a thick gravel pad, and by installing wooden piles where necessary to support the structure. The gravel pad, of a calculated thickness, acts as an insulating blanket preventing the summer heat from melting the permafrost.

Arctic rigs are more compact than many of the land rigs used in southern Canada, so the space requirements may be slightly less. Foundation design on land in the Arctic is not a complicated problem. Oil industry operations, both drilling and production, are successfully conducted at Prudhoe Bay and have been for several years. The onshore operation in the Mackenzie Delta uses the same type of equipment as is used in Prudhoe Bay. Plate 4.3-1 shows a drilling system located in the Mackenzie Delta.

Two types of foundation designs for heavy equipment are used at Prudhoe Bay. The same variations are presently used in the Inuvik area for housing or commercial structures. One method is to use piling which is firmly anchored to the permafrost by freezing. A deck area is then built about two metres above the ground, on top of the piling, to provide clearance space between the floor of the building and the ground. This open air space assures that the permafrost will not be melted and the foundation's integrity will be maintained.

The second method is to use a gravel pad combined with insulation to guard against permafrost melting. The frozen earth provides an excellent foundation. In either foundation type the key is to prevent melting of the permafrost.

Due to the fragility of the vegetation and terrain in the Beaufort Sea - Mackenzie Delta Region, the land area covered by these platforms and ancillary facilities, such as access roads, will be kept to a minimum. Likewise, gravel hauling for construction of the pad and delivery and assembly of the production facilities will be done over snow roads in winter in order to minimize damage to vegetation. Many years of construction experience in the Region exists and confirms this can be done.

Once exploratory drilling is complete, the drilling system is normally moved to another location. Similarly, with production facilities, once all recoverable reserves have been produced, the production facilities can be removed. The gravel pad can also be removed

PLATE 4.3-1 *Drilling onshore in the Mackenzie Delta is similar to onshore drilling anywhere in the world; however, special precautions must be taken to protect the tundra. This is done by covering the tundra with about one metre of gravel before the rig is placed on the site.*

and the gravel used at another site. The area can then be reseeded and restored as closely as possible to its original condition, as shown for example, in Plate 4.3-2.

4.3.2 OFFSHORE DRILLING SYSTEMS

During the past thirty years, drilling offshore in lakes and oceans has moved into progressively deeper water. This has resulted in the evolution of two types of drilling platforms; one which is founded on the lake or sea bed and one which floats and is held in position by anchors or is dynamically positioned.

4.3.2.1 Offshore Bottom-Founded Drilling Systems

Historically, the first offshore wells were drilled from submersible barges in very shallow water. Conventional land rigs were erected on large barges and floated to the drilling site. Considerable innovation was required in order to fit all of the equipment into the limited space. At the drilling location, the sea bottom was covered with approximately one metre of gravel so as to provide a smooth level surface onto which the barge could be ballasted. The depth of the barge was such that the deck remained above sea level.

As the industry moved into deeper water, the posted barge was developed. This system used an extra deck on posts welded to the main deck of a barge and was suitable for use in water three to five metres deep.

As the exploration moved still further offshore, the posted barge concept was no longer sufficient and specialized rig barges, with large columns that enabled the drilling deck to be 15 to 18 metres above the main submerged barge, were designed. The water depth capability was now extended to about 12 metres.

The next development in offshore drilling was the jack-up drilling rig. The first jack-up rig consisted of two barges, one on top of the other. The lower barge was ballasted to the sea floor and the upper barge, on which the drilling rig was mounted, was hoisted out of the water to a height of 10 to 15 metres. Later designs utilized large legs without the bottom barge. These legs were jacked down to the sea floor thus raising the upper barge out of the water.

Plates 4.3-3, 4.3-4 and 4.3-5 illustrate the posted barge, the submersible rig and the jack-up rig. These rigs all have a substantial advantage over a floating system, because there is no motion and the wellhead and blowout prevention systems are at the working surface on the deck of the barge.

PLATE 4.3-2 *After drilling has been completed at the onshore site, the facilities are removed and the area is restored.*

4.3.2.2 Floating Drilling Systems

As offshore exploration pushed into deeper water the floating drilling system was developed. There are two main types of floating drilling systems - the drillship and the semi-submersible.

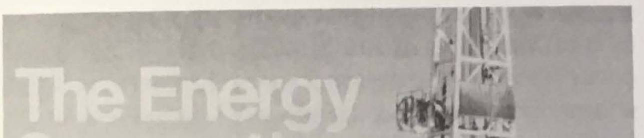

PLATE 4.3-3 *The first offshore drilling started about 30 years ago. It was carried out from barges which were submerged to the sea floor. A conventional drilling rig was mounted on stilts on the barge surface to hold the rig out of the water.*

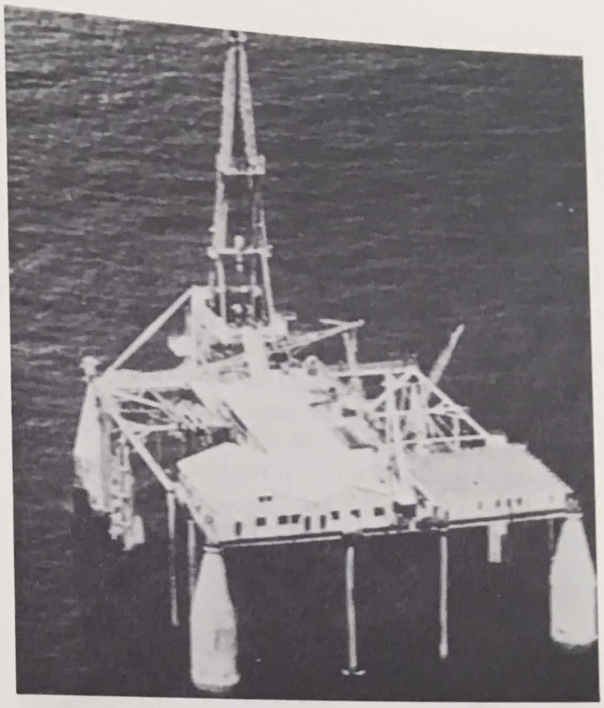

PLATE 4.3-4 *As offshore drilling moved into deeper water, the posted barges were replaced with specially built submersible barges. These barges could be submerged to the sea floor in 10 to 20 metres of water.*

PLATE 4.3-5 *As offshore drilling techniques developed, a specialized rig called a jack-up was developed. A jack-up is a barge mounted rig which has three or four legs that can be jacked down to contact the sea floor when the rig is on location. Continued jacking elevates the barge with the rig above the surface of the water to provide a stable drilling platform.*

The drillship (Plate 4.3-6) which has extended offshore drilling depths substantially, has a drilling rig mounted amidships and performs all drilling operations through the moonpool, a large hole which penetrates the ship from the main deck to the bottom of the hull, and is totally sealed from the rest of the ship. Before drilling commences, the drillship is anchored over the well site by about eight anchors, generally four bow and four stern anchors. The drilling systems are similar to those used on land, except for the blowout preventer, which is located on the sea floor. The riser, a large diameter steel pipe, is connected to the top of the blowout preventer and rises to the surface through the center of the ship in the moonpool.

PLATE 4.3-6 *Floating systems developed concurrently with bottom-founded systems. The first floating systems utilized converted ships. Drillships continue to be a popular system for offshore drilling, particularly in deep water.*

In areas of rough seas and deep water, another type of vessel is used. The dynamically positioned drillship, which does not use any anchors, maintains its position over the well by a computer controlled positioning system that uses the ship's propellers and transverse thrusters in the hull of the ship.

In spite of the strong anchor system, the drillship moves in response to wave and wind action. Sideways motions of the ship can be accommodated to some degree by the flexibility of the riser, while the up and down motion must be compensated with special tensioning devices and motion compensators. The motion compensators enable a constant weight to be kept on the drill strings, whereas the tensioners enable the ship to move up or down without significant dynamic load changes on the blowout preventer.

Limitations of conventional drillships in rough water led to the development of the semi-submersible. Semi-submersibles work on the principle that the effect of wave action extends only 10 to 12 metres below the surface of the ocean. One design of the semi-submersible has two large pontoons and four or more long columns on which the drilling deck is placed, as illustrated in Figure 4.3-1. The semi-submersible has a very limited response to wave action because the bulk of the structure is below the wave zone.

Semi-submersibles are used extensively in areas like the North Sea and the east coast of Canada, where 12 to 15 metre waves and consistently high winds are common.

4.3.3 BEAUFORT SEA EXPLORATION DRILLING SYSTEMS

4.3.3.1 Drillships

To drill safely and efficiently from a floating vessel, it is necessary that the vessel stay on station over the hole that is being drilled. If it is necessary to move away, the move must be conducted in a carefully planned manner. Since moving ice can exert large forces on the vessel and since ice tends to move in a somewhat random way, drilling from a floating unit in the presence of ice involves a number of potential problems. In the absence of any defensive or protective action, the ice forces may cause the anchoring system on a conventional drillship to fail and the vessel to be pushed away from the well. The consequences of this, with respect to well control, depends on whether preparations have been made to plug or seal the well, and what the conditions were in the well at the time. The most serious situation that could occur would be the destruction of the connection and control lines between the blowout preventers on the seafloor and the drilling vessel. If this were to occur, the blowout preventer would automatically close and prevent release of oil well fluid.

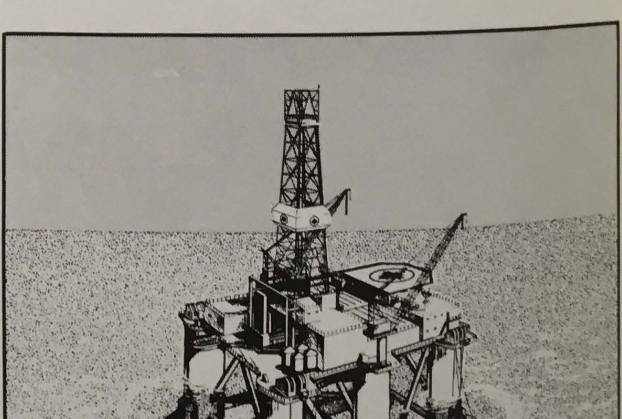

FIGURE 4.3-1 *Semi-submersible drilling rigs were developed to carry out drilling operations in rough seas. While drilling, the semi-submersible is partly submerged so that the bulk of the structure is below the depth of wave action.*

A second threat posed by sea ice comes from the deep keeled ice ridges that may scrape the sea floor in shallow water and could shear off any equipment that has been installed at that point. In normal non-ice situations, the blowout preventers in a floating drilling operation are installed at the seafloor. Blowout preventers provide the sealing mechanism to control pressures in the well; however, if they should be damaged or separated from the well, control of the well may be lost. The threat from ice ridges during drilling from floating platforms in the Beaufort Sea is eliminated by installing the blowout preventers below the sea floor, to a depth below that of anticipated ice scour.

In addition to typical and proven concepts from more temperate areas, the conventional drillships used in the Beaufort Sea have additional capabilities to cope with the environment and to extend the drilling season. The features incorporated into the drillship design include:

- Sponsons on the outer shell to provide double hulls and an ice class equal to Type A under the Arctic Shipping Pollution Prevention Regulations.

- Two underwater thrusters on each side of the ship set at 30° angles to deflect approaching ice floes and to reduce ice friction.

- An eight-point mooring system with remote acoustic release devices.

- An underwater fairlead for each mooring line to reduce contact with ice.

In order to provide a longer season for exploratory drilling from floating vessels, a new type of drillship is presently being designed and built to operate in the Beaufort Sea. Whereas conventional drillships are required to quickly move away from a drill site before threatening ice arrives, these extended season drillships with icebreaker support will have the capability of remaining on location when ice is present.

The conical drilling unit is an example of an extended season drillship designed for Gulf Canada Resources Inc. This unit will be a polygonal structure with 24 equal sides and will have a deck width of approximately 81 m. The unit will have no propulsion system; hence, it will require marine vessel support to be moved to drilling locations. During drilling operations, these units will be supported by Class 4 icebreakers and icebreaking supply ships.

The conical drilling unit will have a deep hull to protect the marine riser (the connection between the drilling equipment and the blowout preventer). The hull will be capable of breaking ice regardless of the direction of ice movement. The shape of the hull is designed to reduce the total ice forces exerted on the unit. The mooring system will be more extensive and stronger than that of a conventional drillship, to ensure that the drilling system remains on location when subjected to the ice forces which occur during early winter. These features will make it possible to drill in the Beaufort Sea over an extended season of about 8 months of the year.

Plate 4.3-7 and Figure 4.3-2 illustrate the conventional drillships used in the Beaufort Sea and the conical drilling unit.

PLATE 4.3-7 *Ice-reinforced drillships were built for the deeper water of the Beaufort Sea. The drillship was the only conventional offshore drilling system that could resist the ice forces.*

4.3.3.2 Artificial Islands

The first offshore well in the Beaufort Sea was drilled by Imperial Oil in the winter of 1973-74. This well was drilled from the artificial island Immerk B-48, where construction had started using a stationary suction dredge in the summer of 1972. This island was constructed at a fairly sheltered location in the offshore delta in a water depth of 3 metres. The first winter demonstrated that the island could withstand the winter ice. After placing additional fill during the next summer, drilling commenced. Plate 4.3-8 illustrates drilling at Immerk B-48.

Up to the spring of 1982, industry has built and drilled from 20 artificial islands in the Arctic. Figure 4.3-3 shows the locations of these islands. Most have been built in the summer by dredging sand from the seafloor, but some have been constructed in winter by trucking gravel over the ice.

Construction efficiency has been gradually improved as working knowledge of the Arctic environment has increased. Table 4.3-1 summarizes basic information on artificial islands constructed and drilled from to date.

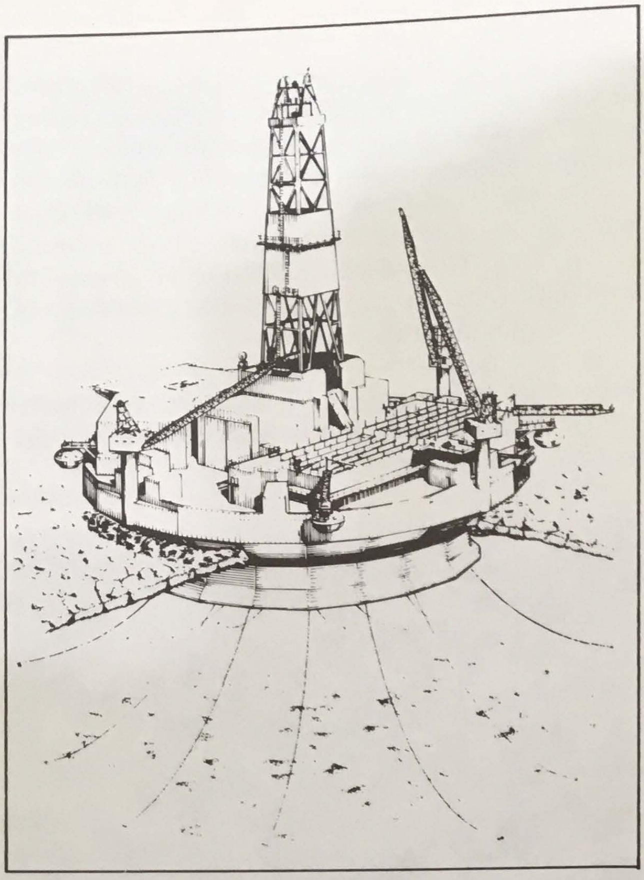

FIGURE 4.3-2 *The conical drilling unit is a specialized drill system that has been developed for the Beaufort Sea and presents an icebreaking profile, like the bow of an icebreaking ship, around its entire periphery so that it can resist much greater ice forces than a conventional drillship.*

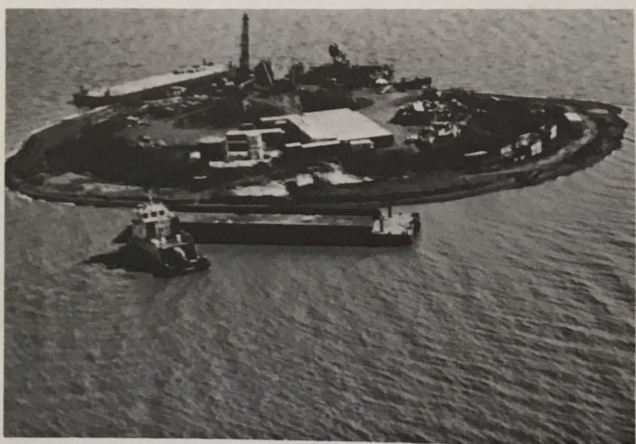

PLATE 4.3-8 *Artificial islands such as Immerk B-48 shown in this photograph provide very suitable foundations for exploratory drill systems in shallow water. A conventional land rig is rigged up after the island is built.*

Most of the earlier islands used weighted slope protection materials such as sandbags to protect the relatively steep upper side slopes of the islands from wave and current erosion. Plates 4.3-9, 4.3-10 and 4.3-11 show the islands Netserk, Adgo and Kugmallit.

Basic changes in building concepts were made as the water depth increased and as experience was gained. Sacrificial beach designs were introduced in 1976

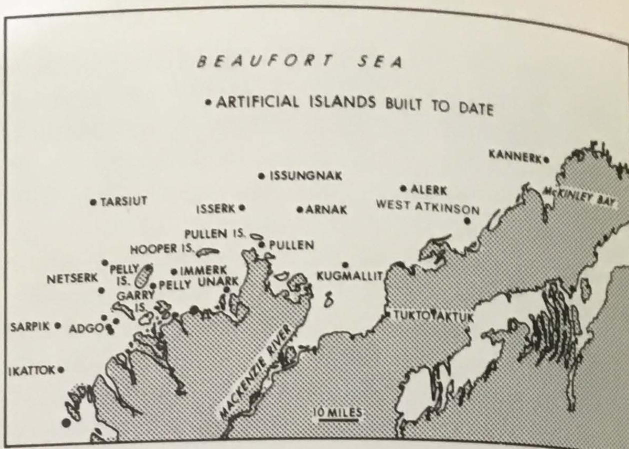

FIGURE 4.3-3 *A total of 20 artificial islands have been built and drilled from in the Beaufort Sea, clearly establishing the feasibility and technology of this type of foundation system.*

with the construction of Arnak L-30 as shown in Plate 4.3-12. Arnak has been followed by Kannerk, Isserk, Issungnak and Alerk which are all of the sacrificial beach design.

As exploration from artificial islands moved into deeper water, island designs have been refined and construction techniques improved; each new island being another step forward in the development of island building technology.

The Issungnak island (Plate 4.3-13), completed in 1979, was built in 20 metres of water using material dredged near the site and supplemented with granular material hauled from Tuft Point. This deeper water island required 5 million cubic metres of material.

One problem with the conventional islands in deeper water is that although construction starts in the early summer, it cannot be completed until the fall. This time of year, though, is characterized by severe and frequent storms, which may interfere with the dredging operations and can result in erosion problems. At this time, the islands are particularly vulnerable to erosion until erosion protection measures are installed.

As islands were built in deeper water, economics necessitated changes in geometry to reduce fill volume requirements. Since the island is a cone, the volume of material required is very sensitive to water depth and side slope of the berm (Figure 4.3-4). Thus, it is apparent that steeper sides slopes minimize fill volume and reduce cost.

This rationale led to the design of the Tarsiut island which was built in 1981 (Figure 4.3-5). The sand berm does not extend to the surface and the side slopes of 1 in 5 to 1 in 7 are steeper than those at the Issungnak island, which are about 1 in 15. Concrete caissons are

TABLE 4.3-1
BASIC INFORMATION ON ARTIFICIAL ISLANDS

Island	Year Constructed	Water Depth m	Construction Season	Operator
Immerk B-48	1972-73	3	Summer	ESSO
Adgo F-28	1973	2	Summer	ESSO
Adgo P-25	1974	2	Summer	ESSO
Pullen E-17	1974	1.5	Summer	ESSO
Netserk B-44	1974	4.5	Summer	ESSO
Adgo C-15	1975	2	Summer	ESSO
Ikattok J-17	1975	2	Summer	ESSO
Netserk F-40	1975-76	7	Summer	ESSO
Unark L-24	1974-75	2	Winter	Sunoco *et al.*
Pelly D-35	1975	2	Winter	Sunoco *et al.*
Sarpik B-35	1976	3.5	Winter	ESSO
Kugmallit H-59	1976	5	Summer	ESSO
Adgo J-27	1976	2	Summer	ESSO
Arnak L-30	1976	8.5	Summer	ESSO
Kannerk G-42	1976	8	Summer	ESSO
Isserk E-27	1977	13	Summer	ESSO
Issungnak O-61	1978-79	20	Summer	ESSO
Alerk P-23	1980-81	11.5	Summer	ESSO
West Atkinson	1981	7	Summer	ESSO
Tarsiut N-44	1981	22	Summer	Gulf Canada

PLATE 4.3-9 *The artificial island of Netserk F-40.*

placed on top of the berm to penetrate the wave zone and, once filled with sand, form a foundation for the drilling equipment.

The Tarsiut island required approximately 1.5 million cubic metres of fill material, which was obtained from subsea borrow areas approximately 65 km and 10 km from the island. Plates 4.3-14, 4.3-15, and 4.3-16 show the construction of the Tarsiut island and the caissons.

The Tarsiut island is also a research platform, being heavily instrumented in order to continue measurement of ice forces. The data obtained from monitoring the ice forces and behaviour at Tarsiut will help to further refine the design of other deep water artificial islands. As more experience is obtained, refinements are made to concepts and design details of islands and caissons currently under development.

PLATE 4.3-10 *The artificial island of Adgo C-15.*

PLATE 4.3-11 *The artificial island of Kugmallit H-59.*

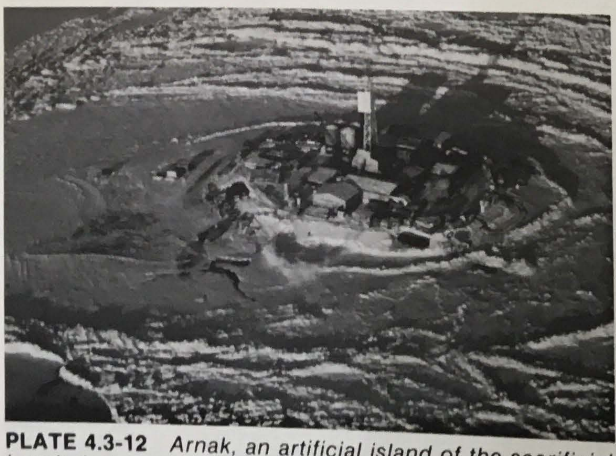

PLATE 4.3-12 *Arnak, an artificial island of the sacrificial beach design.*

Other deeper water caissons are being constructed to further reduce the quantity of dredged material required in the construction of exploration islands. The Caisson Retained Island (Figure 4.3-6) and the Mobile Arctic Caisson (two configurations) (Figure 4.3-7), are two examples of deep caissons which will be in operation in the Region in 1983 and 1984, respectively. Such a unit will be towed to a drilling location, ballast water tanks which are integral to the caisson structure will be filled with water to sink the

PLATE 4.3-13 *The Issungnak artificial island was completed in 1979 in 20 metres of water. Approximately 5 million cubic metres of granular material was required to complete the island, much of it dredged from the sea floor. Sand filled plastic bags placed on netting protect the beach from erosion.*

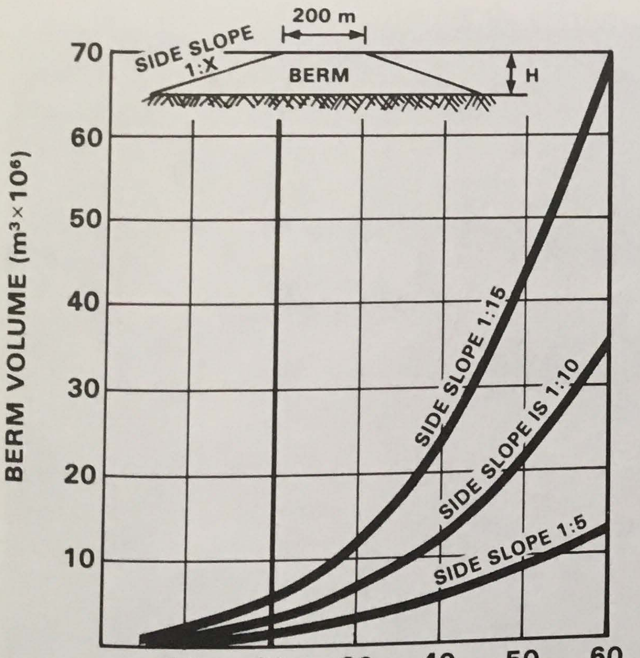

FIGURE 4.3-4 *The geometry of an artificial island significantly affects the quantity of dredged material required for island construction. Steeper side slopes are required to construct islands in deeper water in a timely and economic manner.*

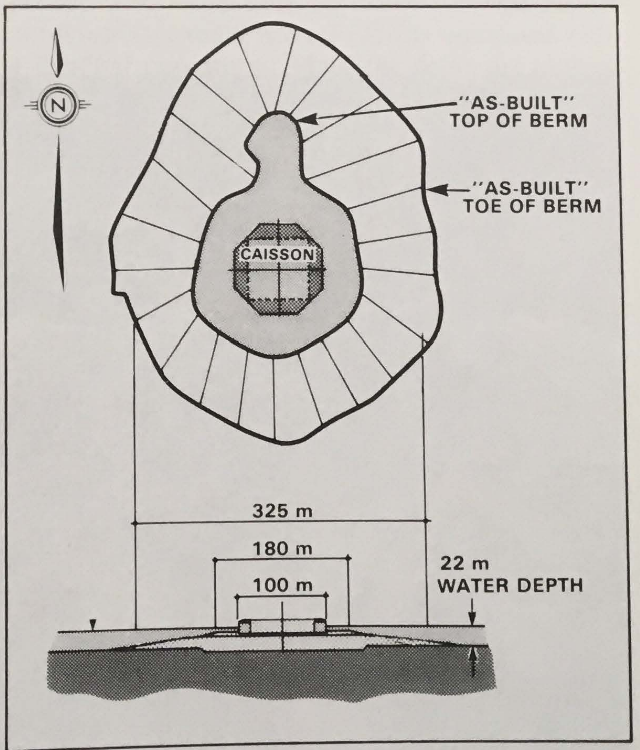

FIGURE 4.3-5 *The Tarsiut island is the island built in the deepest water to date in the Beaufort Sea. It addressed the problem of material requirements by using carefully selected granular materials which were placed on the sea floor to control the side slope at a ratio of approximately 1 to 7. A concrete caisson system was used as a water line penetration system to avoid the problem of island erosion.*

PLATE 4.3-14 *Four large caissons, each weighing about 4,500 tonnes were set into place and sunk onto a prepared earthen berm at Tarsiut.*

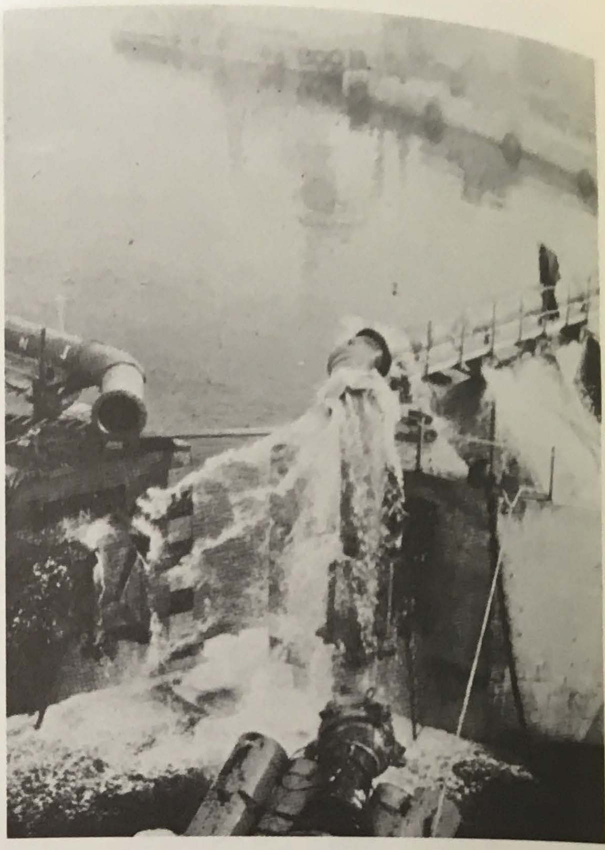

PLATE 4.3-15 *Setting in place of a caisson during the construction of Tarsiut.*

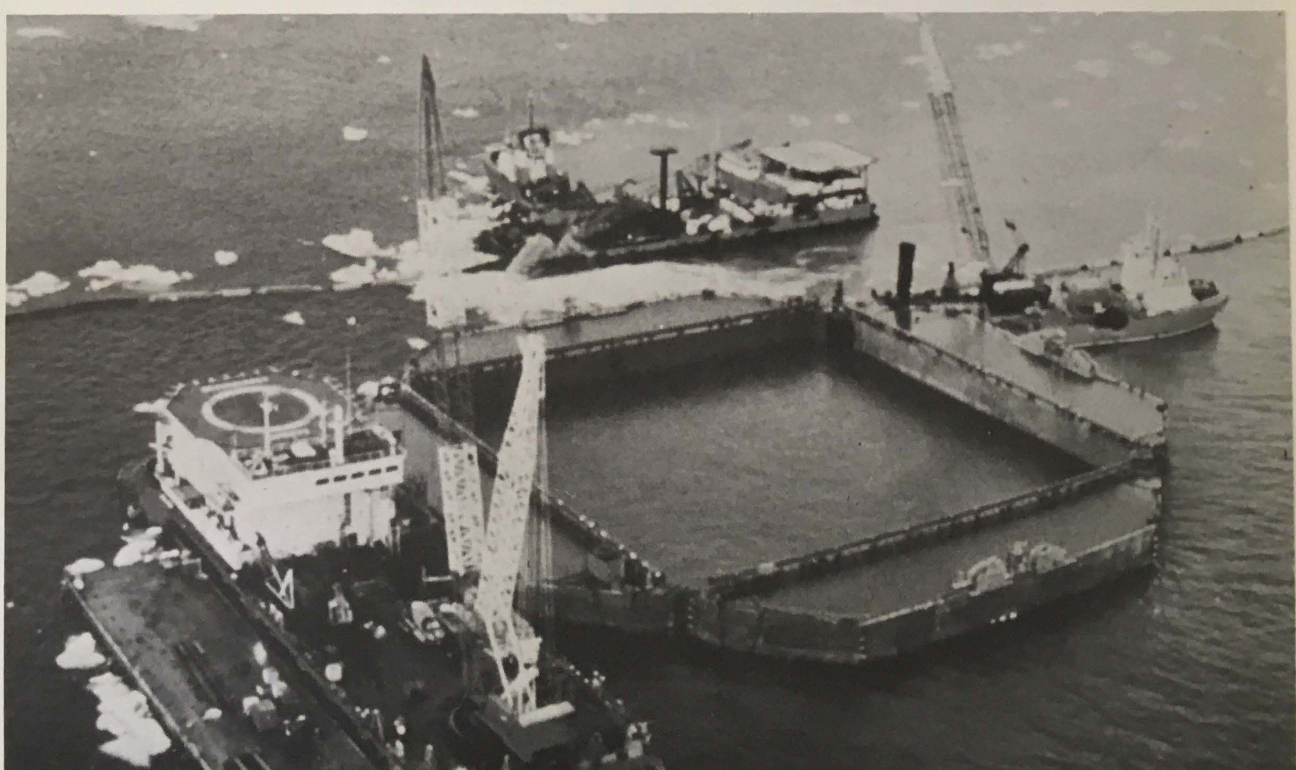

PLATE 4.3-16 *When the caissons were in place, dredged sand was pumped into the centre of the island, stabilizing the structure and providing a foundation for the drilling system.*

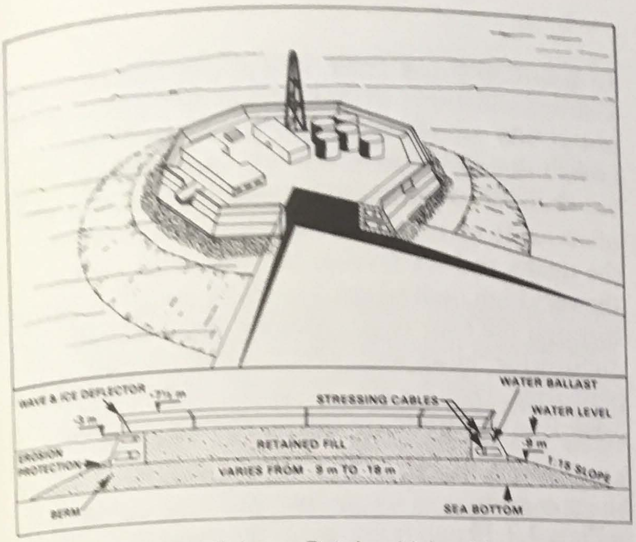

FIGURE 4.3-6 *The Caisson Retained Island is a self contained mobile drilling system that will be used for drilling exploratory wells.*

unit onto a previously constructed earthen berm, and dredged sand will be placed within the centre of the structure to stabilize the caisson. Once drilling is completed at the location, the ballast water is released and the caisson is unlatched and refloated for towing to a new drilling location.

4.3.4 CONVENTIONAL PLATFORMS FOR OFFSHORE DRILLING AND PRODUCING FACILITIES

This section provides a brief history of the development of conventional offshore platforms and describes the platforms which are used for drilling and producing facilities in the Gulf of Mexico, Cook Inlet and the North Sea.

4.3.4.1 Gulf of Mexico

The oil industry extended production to offshore areas in the 1950's in the Gulf of Mexico. The transition was gradual, since many of the lowland coastal areas in southern Louisiana were submerged a great deal of the time due to tidal action. Exploratory drilling was done from floating barges as described earlier, and production was carried out from simple structures anchored to the sea floor by piling. Some of the shallow water fields off the coast of Louisiana were developed with vertically drilled wells. Wellheads protruded above the surface of the ocean and were protected by steel piling.

This type of structure was displaced with larger steel structures from which directional wells were drilled. The early structures were not large enough to accommodate the entire drilling system; only the drill rig was placed on the platform and the rest of the drilling equipment was on a ship anchored alongside. These were called 'tender' platforms. The technology continued to develop until today large steel structures accommodating two drilling rigs, 40 to 50 wells, complete living quarters and production facilities are common. Plate 4.3-17 shows a large steel platform in the Gulf of Mexico.

The limiting design conditions for the Gulf of Mexico platforms are imposed by hurricanes. The platforms are designed to safely resist the forces associated with a hundred year storm. Thus, the decks are always located 15 to 18 metres above normal sea level and the steel structures are firmly anchored to the sea floor with steel piling that is driven 90 to 120 metres below the mud line. In the Gulf of Mexico the designer must

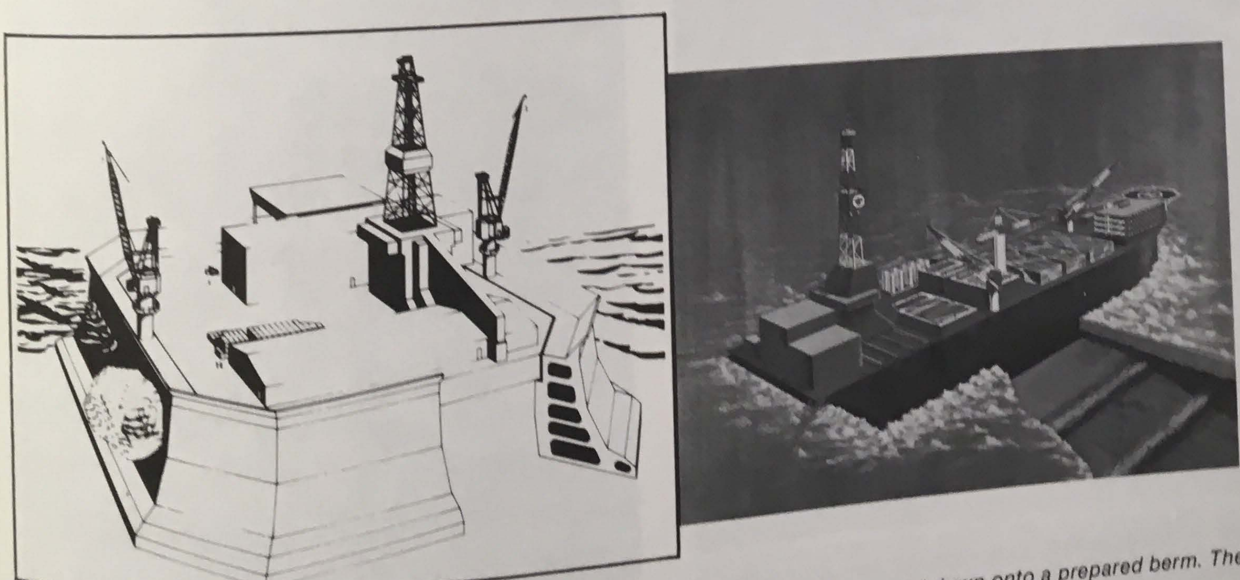

FIGURE 4.3-7 *Mobile Arctic Caissons may be towed to a drilling location and ballasted down onto a prepared berm. The drilling system is moved to a new location when exploratory drilling is completed.*

also minimize the amount of structure that is exposed to wave action, thereby reducing the total wave forces.

4.3.4.2 Cook Inlet, Alaska

Oil and gas were discovered offshore of Alaska in Cook Inlet during the mid-1960's. This area presented a new challenge since Cook Inlet is covered by ice for three or four months of the year. Also, the tides in the inlet range up to 12 metres, and the corresponding tidal currents range up to 4 metres per second.

The inlet is covered with ice throughout the winter months. The limiting design forces on offshore structures are imposed by larger ice floes, sometimes rafted to 4 metres in thickness, and moving at a speed of 4 metres per second. These forces can be combined with substantial seismic forces, since the area is prone to earthquakes, and subject to winds up to 130 kilometres per hour.

These factors rendered the Gulf of Mexico type steel structure unsuitable. New structures had to be designed to resist the ice forces and to also provide protection for the well conductors. Two platform designs emerged. Plate 4.3-18 is the most common structure in Cook Inlet. It is a four columned steel jacket anchored to the sea floor by steel pilings driven about 100 metres below the mud line. There is no cross-bracing between the legs, except close to the sea floor, in order to limit exposure to ice. Clearance of about 16 metres is provided between the bottom of the decks and sea level at low tide to accommodate the very high tidal range. The piling, which was driven through the four large columns, also forms the conductors for the 48 wells which can be drilled from the platforms. Drilling rigs are positioned over the platform legs and wells are drilled through the piling.

The second type of Cook Inlet platform is illustrated in Plate 4.3-19 and is known as the 'monopod.' This is the only platform of its kind in the world. The advantage of this type of structure is that it was very easy to tow from the west coast of the United States, where it was constructed, to its production location in Alaska.

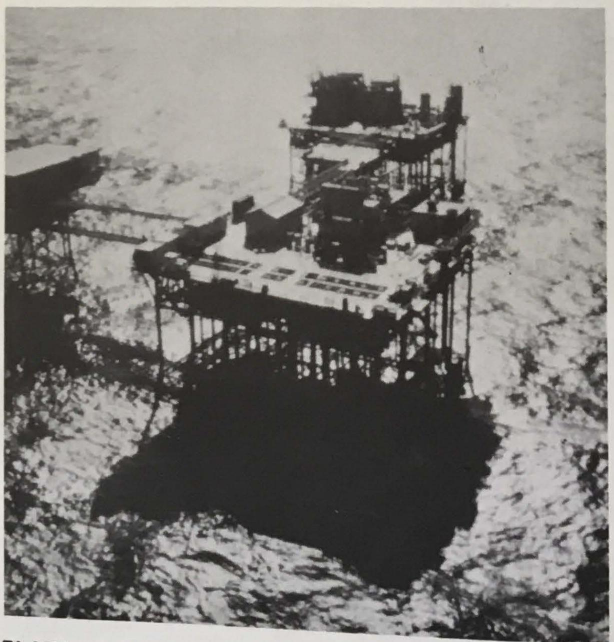

PLATE 4.3-17 *Drilling systems illustrated in previous figures and photographs are mobile exploratory drilling systems. After a discovery has been made, permanent systems must be set in place. In the Gulf of Mexico, the steel jackets are set on the sea floor and anchored with piling. Production and drilling facilities are placed on top of the steel jacket.*

PLATE 4.3-18 *In Cook Inlet, Alaska, which developed in the late 1960's, the Gulf of Mexico steel jackets could not be used because of ice. Cook Inlet conditions have many similarities to Beaufort Sea conditions. In this area, the four column drilling rig was placed on the sea floor and anchored with piling. The wells are drilled through the four steel legs.*

Once on location, the monopod was submerged in place on the sea floor. The platform is anchored to the sea floor with piling driven through the horizontal pontoons resting on the sea floor. Wells are drilled through the central protective column which is 8.5 metres in diameter.

The platforms in Cook Inlet were the largest in the world until the North Sea development commenced, and they demonstrated the ability of the oil industry to respond to new challenges. These platforms were built in the total absence of environmental or other legislation. Operations have been ongoing in the area for over 15 years with no major environmental or engineering problems.

4.3.4.3 North Sea

The discovery of oil and gas in the North Sea presented another challenge to the oil industry. Discoveries in the North Sea have been in relatively deep water up to 150 metres. Severe storms are common in the North Sea, with storm waves frequently reaching 20 metres. These conditions are much harsher than those in the Gulf of Mexico or in Cook Inlet and required new platform designs.

Two types of structures were built to meet these conditions. Plate 4.3-20 illustrates a steel structure similar to those used in the Gulf of Mexico, but many times larger and stronger. This platform contains about 30,000 tonnes of steel as compared to about 10,000 tonnes of steel in an equivalent Gulf of Mexico platform. Plate 4.3-21 is a completely different type of structure called a 'gravity structure.' It is built of concrete and the weight of the structure adequately secures it to the sea floor.

4.3.5 BEAUFORT SEA PRODUCTION ISLAND DESIGN CONSIDERATIONS

The Beaufort Sea is quite different from most of the other seas in the world, where hydrocarbon exploration and production are carried out, because of the ice. Even in summer, the amount of open water is relatively small; this limits waves to smaller heights than are experienced in other areas of petroleum development. Furthermore, the tides are quite small, although storm surges may increase water levels significantly in bays and near the shore (see Volume 3A).

The most important aspect of the Beaufort Sea is the ice, which is present for about 9 months of the year.

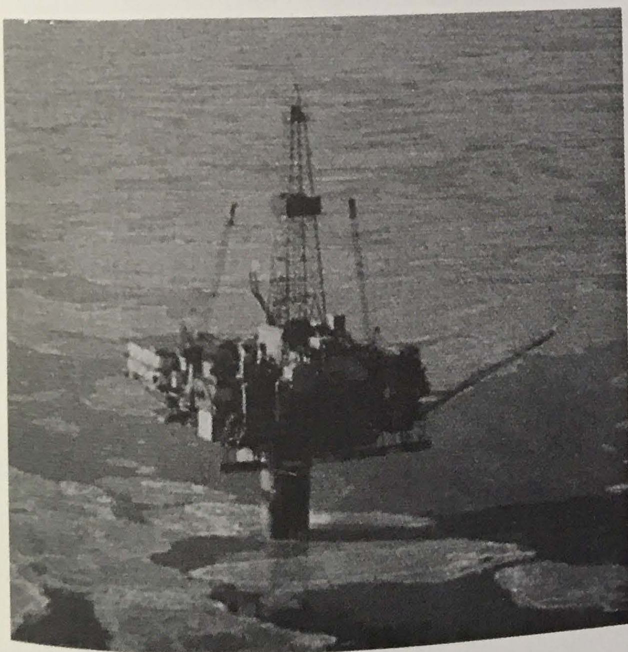

PLATE 4.3-19 *Another type of platform used in Cook Inlet is known as the monopod. This is a single column platform anchored to the sea floor. It presents a very small surface area for interaction with the moving ice.*

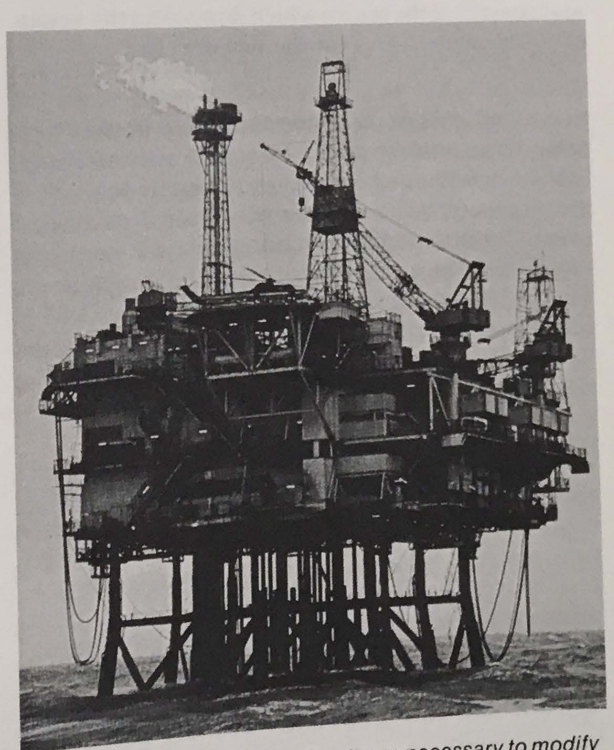

PLATE 4.3-20 *In the North Sea, it was necessary to modify the production platform design because of the very deep water and large waves. The platform shown in this photograph is several times larger than the average Gulf of Mexico platform.*

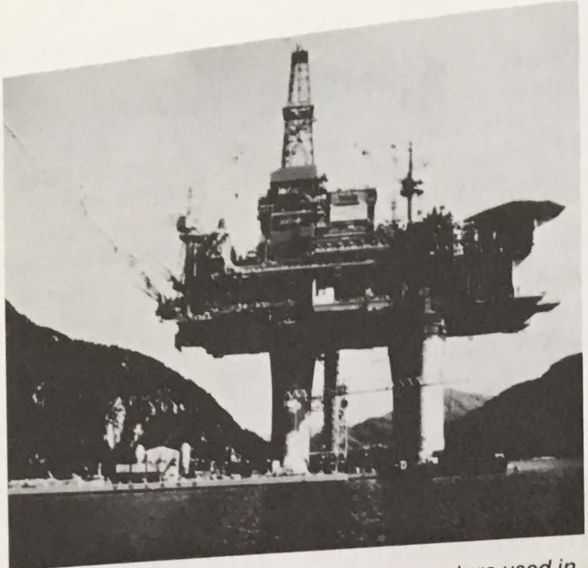

PLATE 4.3-21 *CONDEEP, a gravity type structure used in the North Sea is built of concrete and is secured to the sea floor by its weight. Bottom cylinders are used for storage of oil and drilling takes place through the four vertical columns. (Courtesy of Foster Wheeler Petroleum Development (Canada) Ltd.)*

This ice cover may comprise first-year ice, older multi-year ice, or when extremely low probabilities are considered, ice islands, which break off the ice shelves of Ellesmere Island.

As there are no icebergs, such as occur off Canada's east coast, it is the sea ice which dominates the design of offshore platforms for the Beaufort Sea.

In designing these platforms for environmental forces, it is necessary to design for events with extremely low probabilities of occurrence. These probabilities are expressed as the return period of a particular event. Return periods of 100 years are normally regarded as an acceptable engineering design level. That is, the maximum environmental forces which could occur over a 100 year period are the normal design forces selected for the design of offshore structures.

The designs for Beaufort Sea production structures will be based on proven engineering practice, which makes allowance for the uncertainties in the design parameters. It is the objective of the engineering process to identify and quantify the degree of uncertainty involved in the generation of all design parameters, and to make appropriate allowances for these uncertainties in the design. The level of risk of failure for any structure which is deemed acceptable depends on the consequences of that failure. For this reason, more than one return period can be analyzed for any set of environmental forces. If the results of failure are catastrophic, such as the loss of life or damage to the environment, then only a very low risk is acceptable. For a failure with less severe consequences, such as having to shut in the wells and temporarily abandon the structure, a somewhat higher risk may be acceptable. For repairable damage (for example, having to replace some of the slope protection surrounding an offshore structure damaged by ice over the winter), a much higher risk is acceptable, provided the damage has not made the structure vulnerable to failure.

4.3.5.1 Research

Canadian industry has been conducting research on ice interactions and island building technology in the Beaufort Sea for over a decade. Designs have been developed that are capable of withstanding extreme ice conditions in water up to 60 metres deep. Figure 4.3-8 illustrates the major design criteria requirements and the corresponding types of research that have been conducted (see Volume 7). The successful construction and operation of 19 exploration islands in water up to 22 metres deep has provided experience which contributes to the design of islands in deeper water.

Much of the research has been conducted through co-operative programs of the Arctic Petroleum Operators Association (APOA), an association of petroleum companies with interest in the Canadian Arctic. Due to the high costs of research in the Arctic, the association was formed to provide a vehicle for cost sharing. Research projects are proposed and operated by individual members. Other members can then voluntarily participate in any project, by sharing in the cost of the project in return for the data. This research has contributed significantly to an increased knowledge of ice and its interaction with structures.

In 1969, research and data-gathering activities began with the purpose of providing technology for offshore drilling in the ice-infested waters of the Beaufort Sea. The approach was to consider bottom founded structures, which would have the ability to withstand the loads imposed by moving ice. This required a knowledge of the ice environment, as well as the lateral forces exerted by ice as it failed against the structures.

At that time, available technology was inadequate to deal with the problem. Some experience had been gained in Cook Inlet, Alaska, in dealing with sub-Arctic ice, and bridge piers in ice-infested rivers had been standing up for centuries. Even so, the

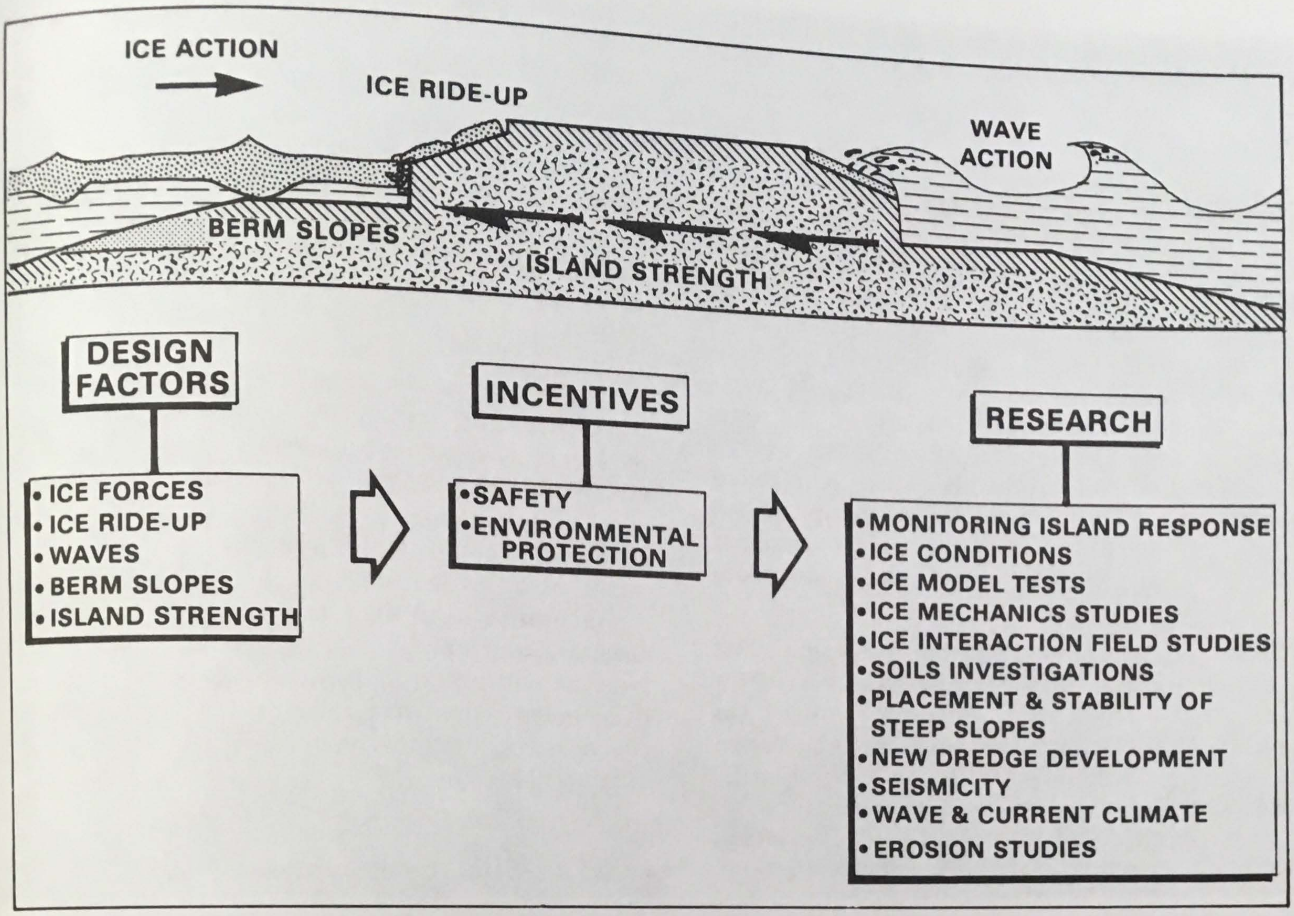

FIGURE 4.3-8 *Artificial islands have been selected as the most practical foundation system for permanent drilling and production facilities in the Beaufort Sea. The factors which govern the design of artificial islands have been the subject of extensive research on island building technology and ice interactions for over a decade. The ice forces are accurately known, as is the ability of man-made islands to resist these forces.*

action of Arctic ice on fixed structures was considered to be a unique problem, owing to the greater strength, thickness and lower temperature of the ice.

Several study areas have been pursued, including general ice conditions and behavior, extreme ice features, and ice strength and forces. Information on ice behaviour and ice conditions have been systematically collected each year since the early 1970's in the shallow waters of the Beaufort Sea (Spedding, 1974, 1981) and in the deeper water areas (McGonigal and Wright, 1980; Wright *et al.,* 1981).

The first experimental Arctic offshore research project investigated the action of an Arctic ice sheet against a vertical pile-type structure (Croasdale, 1970, 1974). This "Nutcracker Project" was so called because of the special devices, resembling giant nutcrackers, which were used to measure the crushing strength of ice against circular piers. The Nutcracker tests provided valuable design data, but also indicated the presence of a size effect, which made it difficult to extrapolate the ice failure strengths to those relevant to large structures. It became obvious that an intensive research effort was required to more fully understand the importance of various ice and structure parameters on ice loading.

It was from this realization that the research effort into ice blossomed. There were many facets to subsequent studies. Experimental ice indentation tests were done on lake ice at intermediate scale with specially designed apparatus (Taylor, 1973; Miller, 1974). Similar tests were conducted at smaller scale on thin ice sheets in a cold room. Field measurements of ice behaviour and ice properties continued (Kry, 1973; Gladwell, 1976). A large outdoor ice test basin was constructed to observe and record ice loading on structures (Verity, 1975). The following outlines some of this work.

The portable field test apparatus constructed for indentation measurements was used at Eagle Lake, a freshwater lake, near Calgary. It consisted of two steel load faces separated by powerful hydraulic cylinders supported in a gantry. The load faces were forced apart in the ice sheet and the failure loads recorded. Three consecutive years of measurements were taken to obtain data on the effect of various parameters. These included the dependence of aspect ratio (indenter width/ice thickness) on the crushing strength of ice, as well as the effect of indenter shape, indenter-ice bonding, temperature and loading rate. Follow-up experimental work using the same apparatus investigated the buckling characteristics of ice

at large aspect ratios (Trofimenkoff, 1975). Field test results were correlated with the mechanical properties determined from cold room laboratory experiments.

These tests identified the ice failure modes for different loading rates and showed that they were an important factor in determining the ice failure strength. Furthermore, these tests, as well as observations of the crushing failure of ice against artificial islands (Gladwell, 1977) and cold room experiments, indicated that the ice did not fail simultaneously in the entire interaction region. Rather, at any one time, different local areas of the interaction region were in different stages of failure. In other words, it appeared appropriate to consider the failure region divided into a number of independent zones, with the number of zones increasing as the structure width increased.

These observations indicated that the design stress for a wide structure should be less than for a narrow structure (Kry, 1979, 1980). A stochastic model was developed, which quantified the decrease in design stress for wide structures, compared to narrow structures. This allowed prediction of ice stresses on artificial islands based on data obtained from tests on continuous crushing of lake ice and in the cold room.

Further direct measurements of ice pressures around islands (Strilchuk, 1977), the observation of ice failure modes around islands, additional continuous crushing measurements at Eagle Lake, and segmented indenter tests in the cold room, added to confidence in the stochastic model for predicting ice failure loads in the interaction zone at an island or other structure.

The presence of ice rubble fields around islands complicated the application of ice failure loads in the interaction zone to a load on the island (Kry, 1977). However, recent work in monitoring the formation, nature and stability of ice rubble fields has added to the knowledge of how they influence the stability of the structure which they surround.

Concurrent with the above studies, experimental data were being gathered on the interaction of ice with conical structures. The main reason for considering conical structures was the reduction in ice force one could expect through bending rather than crushing. This was of particular importance where impact with multi-year ridges could be expected.

To provide confirmation of earlier theoretical and small scale modelling, a large open air ice test basin was constructed in Calgary in 1973. Initially, this Canadian facility was used to test a 45° cone structure at approximately one tenth scale using sheet ice and ridges. The cone was instrumented to measure horizontal and vertical forces and record the ice failure modes. In subsequent years, tests were also conducted on model artificial islands (Semeniuk, 1976), a section of a caisson retained island (Rosenegger, 1977) and recently on a 30° conical structure. Field programs to measure the flexural strength of Arctic ice complemented this work (Kry, 1975). Of particular interest was the determination of the strength of multi-year ice ridges in the Beaufort Sea (Gladwell, 1976).

More recently, research has been conducted at Hans Island, a natural island in the High Arctic, situated in the Kennedy Channel between Ellesmere Island and Greenland (Plate 4.3-22). Each summer when the ice breaks up, large multi-year ice floes move down the channel and collide with this rocky island. Measurements obtained here are the first compiled for the interaction between thick multi-year ice and a large structure, and simulate the interaction expected at a large Beaufort Sea platform. Finally, ice forces are being measured on the Tarsiut artificial island, which is considered a prototype of future deep water production platforms.

4.3.5.2 Ice-Structure Interactions

In most years in the Beaufort Sea, ice forms during October or November and grows to about 2 m thick by late winter (see Volume 3A for more details on Beaufort Sea ice). Landfast ice (which is almost stationary) gradually extends from shore to about the 20 m water depth contour by mid-January to early February. Beyond the landfast ice, in the transition zone, the seasonal pack ice is in constant motion and contains numerous pressure ridges. Further offshore lies the polar pack, consisting of multi-year ice about 3 to 4 m thick with old pressure ridges, which in the extreme, may be up to 50 m thick. Multi-year hummock fields may also occur within the multi-year ice. These hummock fields are formed by extensive ridging at the edges of the landfast ice, bounding the western shores of the High Arctic islands. These features may survive a number of years before calving from the landfast ice edge and drifting seaward. They may be hundred to thousands of metres across, and 10 to 15 metres in thickness when they enter the Beaufort Gyre. There are no icebergs to contend with in the Beaufort Sea; however, occasionally parts of an ice shelf on Ellesmere Island break off to form "ice islands" which circulate in the polar pack. These ice islands can be as thick as 55 m and several kilometres across, but they are very rare, and return periods for collision with a fixed platform are in the order of a thousand years. Nevertheless, structures to be used for production platforms can be designed to withstand these extreme ice features as well as the thick multi-year ice, and hummock fields.

PLATE 4.3-22 *A natural island called Hans Island, situated between Ellesmere Island and Greenland, has been the site of research programs on ice forces for the past few years. This island is about the same size as the artificial islands planned for Beaufort Sea production systems. Scientists have observed numerous collisions of ice with this natural island and have been able to accurately measure the ice forces and ice strengths.*

In waters less than 20 m deep, during late autumn and early winter, the newly formed sea ice moves in the order of kilometres per day, causing rubble fields to form around artificial islands. Large portions of these rubble fields are grounded. As the ice thickens in these shallow water areas, it becomes landfast, and ice movements are generally less than a few metres during a movement event. Once the first-year ice sheet becomes landfast, ice conditions within the landfast ice zone remain essentially unchanged until break-up. The industry experience has shown that this first-year ice poses little threat to artificial island installations.

The probability of a collision between extreme ice features and an offshore structure located within the landfast ice between the time when the ice stabilizes, usually in January, and break-up in early summer, is effectively zero.

During break-up, the landfast ice is weakened by solar radiation, which causes it to fracture into large floes. These drift seaward under the influence of offshore winds, then melt. Rubble fields surrounding islands melt in place, causing fractures to develop in the ice rubble, and when the mass is sufficiently reduced, its buoyancy causes it to lift off the sea bottom and drift seaward.

During the summer months the threat exists that multi-year ice, with an average thickness of 3 and 4 metres, may interact with a structure in the Beaufort Sea. The probability of impact decreases as the water becomes shallower, since the ridge keels contained within the multi-year ice will limit the multi-year floe travel into shallow water. Figure 4.3-9 shows estimates of the average summer concentration (%) of multi-year ice in the general area of interest (Marcellus and Morrison, 1982).

An assessment of impact probabilities for multi-year floes has been conducted for general sites, based upon the average summer concentration of multi-year ice at the sites (Marcellus and Morrison, 1982). For example, Tarsiut lies along the estimated 3.5% contour, whereas Kopanoar is closer to the 5.5% contour. An estimate of the impact rate of multi-year floes with diameters greater than 500 m has been established and indicates that approximately 40 floes of this size range may impact a point structure located along the 5% contour during the summer months. Likewise, for the winter months, for a structure located outside the landfast ice at the 5% site, approximately 28 multi-year floes with diameters greater than 500 m may impact a point structure in one winter season. Multi-year ice invasions tend to be

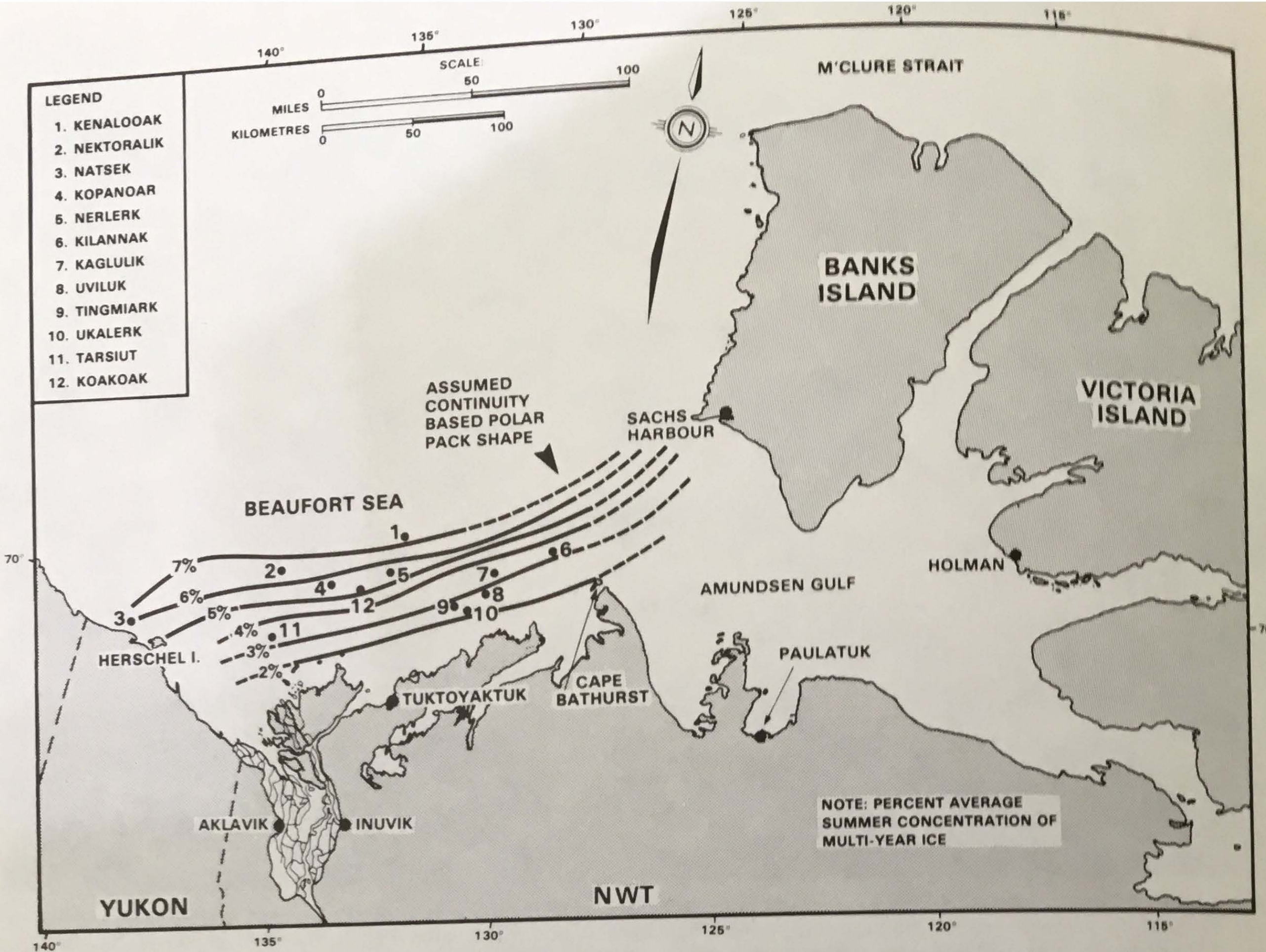

FIGURE 4.3-9 *The largest regular forces in the Beaufort Sea are exerted by multi-year ice. This diagram illustrates the average concentration of multi-year ice in the area of interest.*

episodic and do not occur every year. For other sites these numbers may be scaled up or down according to their multi-year ice concentration percentage. These numbers are considered conservative and are high in comparison to actual observations at the deeper artificial islands constructed to date in the Beaufort Sea. Additional investigations are currently underway to improve upon the initial estimates. Estimates of the size and velocity distributions for multi-year ice floes have also been made for both winter and summer.

Multi-year floes have ridges contained within them. From analyses of bottom profiles of the pack ice north of the drill sites, it was found that, on average, one ice keel with a depth greater than 3 m was observed for every 200 to 300 m of the ice sheet. By combining this information with the depth distribution of these ice keels, an assessment was made of the thickness of the multi-year ice with ridges that may interact with Beaufort Sea structures.

Multi-year hummock fields are formed from ice rubble generated along the western edge of the Arctic Archipelago. These ice features tend to differ from multi-year ice floes in their mass and extent. Since they are formed from ice rubble, they develop a very irregular and varied geometry. Very few multi-year hummock fields have been observed in the southern Beaufort Sea and few measurements have been made to date on these features. However, a clear definition of a hummock field has been lacking, and in the past, hummock fields may have been considered very rough multi-year floes. For the purposes of industry work in the region, a hummock field has recently been defined as a multi-year ice floe which has a diameter of greater than or equal to 500 m, and an average thickness greater than or equal to 10 m (Marcellus and Morrison, 1982). Using this definition, an assessment of the number of hummock fields in the pack ice north of the drill sites was conducted using the under-ice profiles obtained from a submarine run. The relationship between the number of hummock fields and the number of multi-year floes was found to be 1 in 65. Therefore, on average, an impact with a hummock field could be expected about once every 1.5 to 2 years in water depths of 60 metres during the summer, and about once every 5 years during the winter at these sites. The thickness distribution for hummock fields was obtained from a submarine run along the west coast of the Queen Elizabeth Islands where more hummock fields are found.

The foregoing assessments were based on general annual ice statistics, which are necessary for an analysis based on return periods. Ice conditions, however, can vary greatly from year to year in the southern Beaufort Sea. In some summers, multi-year ice may never come into the areas of the drill sites; whereas, in other years, the multi-year ice may be present in various concentrations throughout the summer. For instance, in 1974, onshore winds pushed multi-year ice into the area of the drillsites and it remained there most of the summer.

The analysis of ice loads on offshore structures in the Beaufort Sea is based on the most probable ice feature which may interact with the structure during its lifetime. Section 4.3.6 describes the ability of each structure to resist the various ice features.

4.3.5.3 Ice Pile-up and Ride-up

When sea ice moves against an obstruction such as an artificial island or a beach, it can either flex upward and ride up, or fail against the obstruction, producing a pile of ice rubble.

In early winter when there are extensive movements of thin ice, artificial islands in the Beaufort Sea have been observed to cause the formation of ice rubble piles. During ice movements, pieces of the sheet broken off by impact with the island cannot pass around the structure and are too thin, and therefore too weak, to ride-up onto the island. The ice thus breaks up and remains near the edge of the platform as a pile of ice rubble. Even if a pile-up were to grow to a sufficient height to cause a spill over of ice rubble onto the island surface, this loose material could be fairly easily controlled by a retaining wall. Notwithstanding the foregoing, it is possible that ice could ride up onto the surface to threaten the safety of personnel and installations. Therefore, vulnerable facilities are located at a sufficient distance away from the island edge.

When a rubble pile is already formed, the ice sheet moving toward it may actually penetrate the rubble before being deflected and broken. Once the rubble pile grounds and reaches a critical height, it will extend seaward. The ice forces at work in this process during early winter are quite small and the rubble height rarely exceeds 7 metres. Later in winter there is less ice movement but the ice sheets are much thicker. Thus, if movement does occur, higher rubble piles usually result.

As the winter progresses, the rubble consolidates, so that by late winter, it behaves as a rigid grounded mass which shields the island from direct contact with moving ice sheets or extreme ice features. Movement of the rubble fields themselves, within the landfast ice, have been measured at less than one metre per day. The rubble also protects an island from ice forces by increasing the sliding resistance. This resistance is, however, counterbalanced to a large extent by the increased area over which an advancing ice sheet will interact with the obstruction.

Industry and others have been conducting research on ice pile-up and ride-up for many years and observations of ice action on existing artificial islands in the Beaufort Sea have provided valuable field evidence.

Kovacs and Sodhi (1980) reviewed occurrences of ice ride-up and pile-up for the period 1835 to 1979. For the 24 extreme cases of ride-up on sloping beaches, the mean maximum elevation gain was 9 m above sea level. A resident of Sachs Harbour reported, however, that ice has overriden 15 m hills near the beach. The mean reported length of extreme ride-up was around 100 m past the shoreline. In one unexplained case at King Christian Island in 1835, the ice continued for 800 m inland. A field study at Hans Island in 1981 provided evidence of an ice ride-up of 11 metres above sea level.

Since the maximum height of historical ice ride-up has not exceeded 15 m, freeboards between 20 and 30 m will be provided for production islands to ensure that the facilities will not be threatened by ice ride-up. Furthermore, ice ride-up has only occurred on shallow sloping beaches, and never over vertical walls, as will exist on caisson-type drilling or producing islands.

Of the 24 extreme cases of pile-up reviewed by Kovacs and Sodhi, the maximum elevation gain has been about 11 m above sea level. The maximum observed rubble pile height occurred in 1975 at Somerset Island, where a cone shaped rubble pile reached 30 m. In 1974 and 1981, 25 m of rubble piled up at Hans Island. No pile-ups of this magnitude have been reported for the Beaufort Sea.

In model tests of ice interactions with a caisson-retained island, it has been found that steeper barriers resist override and instigate a pile-up of advancing ice (Jahns, 1979). It has also been suggested that an established rubble pile of early season ice, serves as an effective line of defence against later override. High beach friction and abrupt slope changes were felt to be effective triggers of pile-up. More recently, in a series of tests in which artificial ice was forced against a model beach, it was found that as the angle of the beach was increased, the ice showed an increasing tendency to fail in crushing, producing a pile-up, rather than a failure in flexure, which would initiate an override. When similar tests were conducted with a vertically-walled caisson model, ride-up never occurred, even when encouraged with an ice-ramp placed ahead of the caisson walls.

Several theoretical models have been developed to predict the phenomena of ice pile-up and ride-up. The results of research by Croasdale *et al.* (1978) indicate that pile-up, rather than ride-up, can be encouraged by increasing beach slopes, beach lengths and freeboard. A good design to resist ice ride-up is one with a vertical or near-vertical face at the water line. When ice acts against such a structure, initially loose rubble is formed which will be deposited both on the surface of the ice and below the ice. This process will continue, with the ice penetrating the rubble until eventually the rubble beneath this ice becomes grounded on the underwater berm of the structure. At that point rubble could continue to be forced beneath the ice, raising its leading edge and initiating a ride-up. However a theoretical energy balance indicates that it is much more likely that rubble will continue to build above the water line, thereby enhancing the pile-up and providing a barrier to ice ride-up.

Kovacs and Sodhi (1980) showed that a rubble pile is an effective barrier to ride-up. Using measurements at actual sites, they calculated that the minimum force required to slide rubble up a beach exceeds the force required to continue rubble pile-up by a factor of 3 or 4.

In summary it can be stated that an ice ride-up could pose a threat to an offshore installation if it were to occur. However, theoretical analyses, scale-modelling, and field observations indicate that ride-up will not occur onto the surface of production islands. An extreme case of pile-up could result in some loose rubble spilling onto the surface of a production island. The amount would likely be small and it would not pose a significant threat to operations.

4.3.5.4 Ice Forces

When ice moves against a structure it exerts a force. The governing force for design is determined either by local failure of the ice in front of the structure, called "limit stress," or by the limiting driving force which the pack ice can concentrate onto the structure, called "limit force" (Croasdale, 1980). These ice force concepts are illustrated in Figure 4.3-10 (Croasdale and Marcellus, 1981).

For relatively narrow structures and thinner ice, the limit stress load will govern. The load is a function of the ice thickness, the structure width and the ice strength in the relevant mode of failure (bending, crushing or buckling).

Ice will normally fail in bending against a sloping structure at lower forces than in crushing against a vertical-sided structure. However, for a structure which is wide relative to ice thickness, the ice clearing forces may become so high as to negate the advantages of the sloping geometry. In fact the ice may not

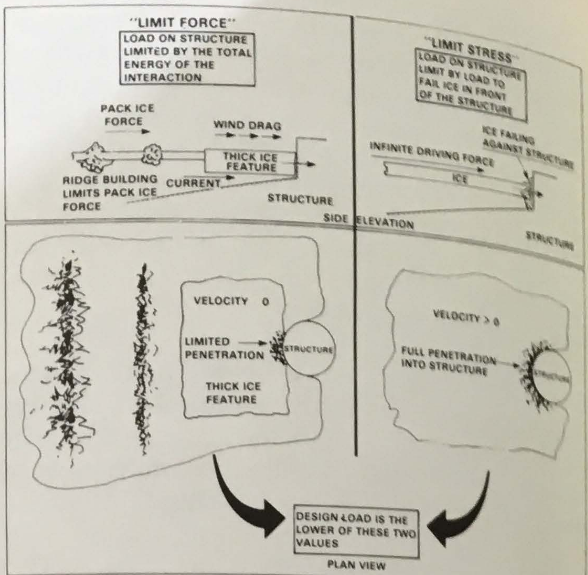

FIGURE 4.3-10 *When the moving ice collides with a structure it is necessary for the structure to resist the impact.*

clear around a wide structure, thus creating an ice rubble pile. As ice continues to move, it acts on the outside of the rubble and the structural shape becomes irrelevant.

The so-called ice strength parameter is a complex issue that has taxed the ability of scientists and engineers for several decades. The issue is complicated by the fact that ice is a difficult engineering material to deal with. It is a material close to its melting point, so it exhibits creep, and its deformation characteristics are sensitive to temperature. Ice is also a brittle material when loaded quickly, but ductile at slower loading rates; thus its strength is sensitive to loading rate or strain rate. The crystal structure of the ice also influences its strength. Finally, ice is a natural material containing many cracks and flaws; their presence leads to lower strength with increase in the volume of ice being loaded.

From a scientific viewpoint there are still some gaps in our knowledge of ice strength, however, much significant research has been conducted during the past decade. From a pragmatic engineering viewpoint, sufficient understanding now exists to safely predict ice forces on offshore Arctic platforms. In this respect it should be noted that small-scale measurements of ice strength generally yield higher values than those which occur in the field on a larger scale. Experience to date with artificial islands in the Beaufort Sea indicates that ice force predictions based on small-scale strengths and narrow structures are conservative where applied to relatively wide structures such as artificial islands.

The ice forces for the design of deeper water Beaufort Sea structures are governed by extreme ice features such as the rare ice island, multi-year hummock fields and large, thick multi-year floes. A methodology has

recently been developed which recognizes the varied stages of interaction of such features with offshore platforms. (Croasdale, 1980; Croasdale and Marcellus, 1981).

In the initial stages of interaction of such large ice masses, the penetration into the structure is governed by the kinetic energy of the ice feature. In fact the "limit force" approach is only valid if the ice feature can be stopped before it fully envelops the structure. At this stage in our knowledge the best approach to stop a large ice feature appears to be to design a structure with a protective sand berm below the waterline. The sand berm has to be large enough to stop the large ice feature before it penetrates sufficiently to cause catastrophic damage. In engineering terminology, the work done in deforming the sand berm and lifting the front end of the ice feature has to balance the initial kinetic energy of the ice feature, plus the work done by the external forces during the slowing down process. The external forces are wind drag, current drag and ridge-building forces from the surrounding pack ice, if present.

This approach indicates that it is possible to stop a hypothetical ice feature such as a large ice island (10 km by 10 km by 50 m thick) before it reaches the central core of an artificial production island if a protective subsea berm is provided. After the ice feature has been brought to rest, the ice forces are limited by the driving forces on the large ice feature. These ice forces can also be comfortably resisted by typical production platform designs. Thinner ice features which clear the berm will generate forces on the waterline portion of the platform and can be calculated using the limit stress approach, although in some cases there may not be sufficient energy and driving force to cause full envelopment of the structure.

Verification of the physics of the interaction models are underway. The two main areas of investigation are the ice-soil deformation process and large-scale crushing strengths of multi-year ice (see Volume 7).

The models can be applied deterministically or statistically, the latter being a more valid engineering approach. The statistical approach recognizes firstly that there is an extremely low probability that a large ice feature will collide with a fixed point in the Beaufort Sea; secondly, that even if it does, it may not be moving at maximum velocity nor subject to maximum levels of driving force from wind, currents and pack ice. One can then consider the maximum probable ice feature which may interact with a structure during its lifetime and base the design criteria on this event.

To quantify the statistical approach, a probability model has been developed using the "Monte Carlo" approach, which integrates statistics for collision, floe sizes, ice thickness, velocity and driving forces. By simulating thousands of years of ice movement past a structure of particular geometry, statistical ice loads are generated, representing the selected risk levels (or return periods). From this kind of analysis the maximum probable ice feature can be selected and ice loads calculated. This ice feature is then used to conduct sensitivity analysis for various structural geometries to determine the optimum geometry for a particular structural concept.

4.3.5.5 Observed Ice Interaction with Existing Islands

Observations on ice behaviour around exploratory artificial islands has contributed greatly to the knowledge of ice interaction with structures.

In shallow locations, for example, at the Adgo artificial islands, the ice quickly becomes landfast once freeze-up commences.Thereafter, the ice moves minimally in response to wind stress or thermal expansion. Small pile-ups occasionally form, caused by strong winds at the time of freeze-up. Because of the limited movement, the ice sheet tends to be relatively smooth around the islands, remaining unchanged until break-up. Some cracks are formed by tidal action but this activity also reduces as the ice freezes to the bottom at these shallow water locations. During break-up, ice around the shallow water islands usually melts in place.

In summer, invasions of ice seldom occur because the thicker multi-year ice with ridges grounds in deeper water before reaching the shallow water islands. Islands at which this typical ice behaviour pattern was observed were Adgo F-28, Adgo P-25 and Ikkatok J-17 (Croasdale and Marcellus, 1978; Gladwell, 1977).

In the deeper locations it takes longer for the ice to become landfast, thereby exposing the island to large movements of ice sheets of typically 0.5 m thickness. Under storm conditions, these ice movements create extensive grounded rubble fields around the island. However, once the ice becomes landfast, movements are generally limited to the order of 1 metre per day and tend to be cyclic. These movements, coupled with tidal action, are sufficient to maintain an unfrozen "active" crack around the periphery of the rubble field.

At break-up, fractures develop in the grounded ice rubble. When its mass is sufficiently reduced, buoyant forces lift the grounded ice pieces off the sea bottom, allowing them to drift away.

The following describes the ice interaction observed at Netserk F-40 (7 metre water depth) in the winter of

1975/76, and at Isserk E-27 (13 metre water depth) in the winter of 1977/78. It is anticipated that these observations are typical of the ice behaviour to be expected at other islands in similar water depths.

(a) Netserk F-40, Winter 1975/1976

New ice began to form in Mackenzie Bay during the last week of September. The new ice quickly extended out to where the water was 13 metres deep, encompassing the Netserk artificial island positioned just off the Mackenzie Delta. This ice did not become completely landfast and stable until mid-November. Near the end of October a large 90 m ice movement caused the formation of an extensive rubble field. Following this event, cyclic movements of several metres in response to winds increased the size of the rubble pile. An active crack was always present around the edge of the rubble field, opening and closing in response to ice movement (Gladwell, 1977; Strilchuk, 1977).

In early February, a storm with strong winds caused ice movement from the northwest. The ice was about 1.5 metres thick and moved at a rate of 0.5 cm per second. A new rubble pile about 12 metres high was thus generated on the northwest edge of the existing pile-up. The seaward slope of the pile lay at an angle of about 60° with ice pieces averaging 0.25 to 0.6 metres across. The fact that the pieces were smaller than the thickness of the ice suggests that the ice failed in crushing against the island. At the same time a pressure ridge was formed running in a southwest direction. Although there was substantial movement to the north of the pressure ridge, there was no perceptible movement of the existing rubble pile. This pile effectively protected the island from the movement of the ice sheet.

After this, ice movements were small and cyclic. Throughout April the ice sheet moved continuously but slowly from the south. It is probable that warming of the ice sheet, causing thermal expansion, was the driving force. Although there were some extended periods with very little ice movement, tidal action maintained an open crack around the island throughout the winter.

(b) Isserk E-27, Winter 1977/1978

Isserk was completed with a 3.5 metre freeboard in October 1979. By the end of November there were large mobile ice floes about 0.4 metres thick in the vicinity of the island. Ice movement created a rubble field at the island. The major and minor axes of the rubble field had lengths of 700 and 500 metres, with mean height of the rubble of 2 to 2.5 metres and maximum heights of 6 to 9.5 metres. The rubble field was probably well grounded. The ice within the 2 metre water depth contour was relatively smooth with ridges at the periphery.

Ice movement continued to extend this rubble field until late December, when the ice became landfast. By then the rubble field had increased to twice its original extent towards the northwest, but changed little to the south and southeast. Dimensions of the rubble field at this time were 1,400 and 700 metres along the major and minor axes.

In spring, an open water area developed due to melting in the immediate vicinity of the island. By mid-June, a water moat approximately one half the island diameter had formed around the island perimeter. Numerous cracks also developed in the rubble field beyond the melted area. As melting continued and the surrounding landfast ice disintegrated, sections of the rubble broke away. The major portion of the rubble field had disintegrated by mid-July when the drilling rig was removed by barge. Grounded rubble which remained had to be broken to permit anchoring of the barge on the island beach.

4.3.5.6 Protection Afforded by Grounded Rubble

Experience demonstrates that artificial islands in the Beaufort Sea induce the formation of ice rubble piles in the early winter whenever there are extensive movements, the broken pieces of the ice sheet formed 13 m high and extending over 10 island diameters (1 km) have been observed (Kry, 1977). During ice movements the broken pieces of the ice sheet formed by interaction with the island slope cannot move around an island as they can around narrow structures. To date, no ride-up onto the island working surface has occurred.

The mechanics of ice rubble pile formation are varied. In some cases the ice sheet deflects upward or downward, failing in bending. At other times the ice penetrates the rubble pile before deflecting upward and failing in bending (Parmeter and Coon, 1972). When extensive ice movements occur, the rubble builds until it grounds, and once a certain height is reached, it grows seawards. Ice forces during this process are low. In the early winter the rubble height rarely exceeds 7 m.

As winter progresses, ice rubble formation activity decreases with the diminishing ice movements; but if movements of thicker ice (1 to 2 m in thickness) do occur, higher rubble piles result. As well, the rubble pile consolidates, so that by mid winter the rubble behaves as a rigid grounded mass which shields the island from immediate contact with thicker ice. Through grounding, it also provides some protection to the island due to its sliding resistance. This sliding resistance to ice forces is dependent on the average rubble height above sea level, as well as the characteristic ice rubble sail and keel porosities (Frederking and Wright, 1980). However, the resistance to ice

forces is counterbalanced by the effective increase in island diameter caused by the rubble, which presents a wider area for advancing ice interaction.

4.3.5.7 Wave Conditions

Wave conditions in the Beaufort Sea must be taken into account when designing offshore platforms. Understanding of wave conditions comes from three sources: direct observation, estimates based on recorded wind data and pressure charts, and estimates derived from hypothetical severe storm scenarios.

The most reliable source of information is direct measurements with Waverider buoys. These wave recording devices have been supplied by the government's Marine Environmental Data Service. From one to four Waverider buoys have been used to gather data each summer since 1975. Unfortunately, the usefulness of these data are restricted by the limited duration and sporadic coverage of the program. In order to obtain longer and more continuous estimates of the wave regime, hindcast techniques have been used to predict extreme situations. In hindcast studies, recorded wind data and pressure charts are used to estimate wind and wave conditions. A number of such studies have been performed for the Beaufort Sea (Baird, 1980; IRC, 1977; Dames and Moore, 1975; Seaconsult, 1981). A recent study (Baird, 1980) estimated the wave conditions at six locations in the Beaufort Sea every hour over the open water periods between 1970 and 1979. The estimated wave conditions were checked against available Waverider buoy records. The reasonable agreement between hindcast and measured wave conditions adds credence to the results (see Volume 3A for further information on waves).

It is also necessary to estimate the severity of extreme storms which could occur in this area. Since it is very unlikely that such storms have occurred during the limited time over which meteorological records have been kept. The only methods of estimation are examination of historical records and extrapolation from less severe but more common storms, to derive an estimate of the most severe storm that can occur. The second method is that which has been used most often both in the Beaufort Sea and elsewhere. However, Seaconsult (1981), using the meteorological historical records, have deduced the wind field associated with the most extreme storm event that is physically realizable. The relevant meteorological data associated with such a storm have been used as input to a wave climate model to estimate the most severe wave conditions that are ever likely to occur.

In designing offshore platforms for normal wave conditions, the key factor used is the frequency with which waves exceed a stated significant wave height. For more severe storms, the return period for a storm of given severity (peak wave height) is the measure used in designing a structure to withstand wave conditions. Although wave heights in the Beaufort Sea are generally very low, severe storms do sometimes occur in the fall. At times these have been severe enough to bring all dredging operations to a halt. Islands under construction are particularly vulnerable, because at this time of year they are likely to be in the late stages of construction, that is, penetrating the zone of wave action at a time when slope protection provisions or caisson installations have not yet been completed.

Since wave heights in the Beaufort Sea are very low compared to other areas such as the North Sea, where structures are designed to withstand 30 m waves, wave action does not present a problem of structural safety once a platform is complete. Rather, it is of importance in designing erosion protection. Deep water production platforms in the Beaufort Sea are likely to be artificial islands topped with a prefabricated caisson structure which will penetrate through the zone of wave action.These will be more erosion resistant. In the case of the bermed island or atoll structure, the subsea berm will extend to about 10 metres below the water surface, and thus will generally be unaffected by wave action. Caissons will also be used in the construction of shallow water islands; however, conventional methods of slope protection such as rip-rap, will also be used at some shallow water locations.

4.3.5.8 Ocean Currents

Currents in the Beaufort Sea are of some concern in the design of offshore structures because of the potential for erosion of unprotected sand surfaces below the wave action zone. Figure 4.3-11 is a typical frequency distribution for current speeds, based on a long term summer and winter current measurement program at a deep water site (Fissel, 1981).

This type of information will be used in the design of offshore production platforms. As illustrated, current speeds are generally low. Even allowing for the fact that the presence of a structure may cause a localized increase in current speed by a factor of 1.5, the speed will seldom exceed 0.3 metres per second, which is the speed required to transport medium grained sand particles. However, during storms, speeds may exceed 0.3 metres per second. While little variation is apparent at deep water sites, recent observations in shallow water show speeds increasing to over 0.7 metres per second during storm events.

4.3.5.9 Mean Water Level Fluctuations

The mean water level in the Beaufort Sea will fluctu-

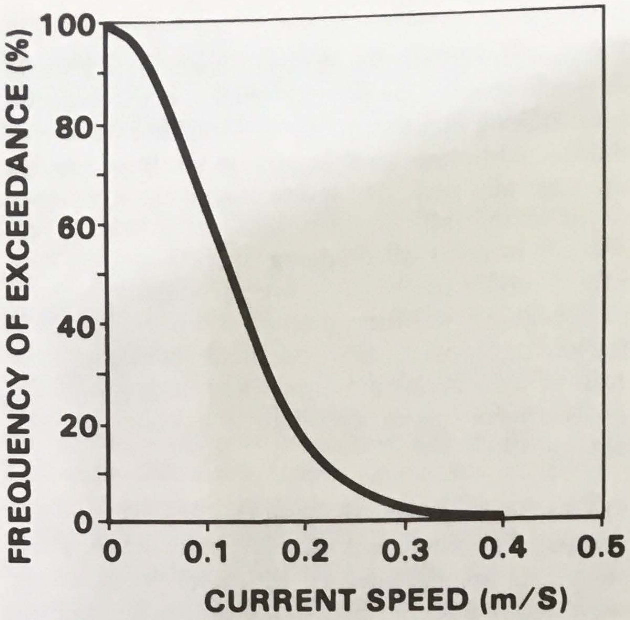

FIGURE 4.3-11 *Ocean current speeds are generally low in the Beaufort Sea. As shown in the above frequency distribution of current speeds which were measured at a deep water site, current speed seldom exceeds 0.3 m/sec.*

ate due to tides and storm surges. Tidal ranges in the Beaufort Sea are low, typically less than 0.5 m. Larger fluctuations are possible along the coast due to storm surges; however, storm surge amplitudes well offshore are too small to pose any hazard to an offshore facility (Henry, 1975).

4.3.5.10 Geotechnical Considerations

As with all major civil engineering projects, detailed delineation of the foundation soils is required in advance of construction. This is normally conducted by combining the information from boreholes and shallow seismic traces at the site. Detailed engineering calculations of the stability of the foundations under the anticipated loading by the platforms, and environmental forces, are then conducted. Both short-term and long-term stability is assessed. For short-term stability the loads imposed on the seabed soils during and immediately following construction are assessed. Long-term stability calculations involve the lateral stability against ice loading on the platform, the bearing capacity and settlement of the seabed soils, and the effect of earthquakes.

For some sites, where the surficial sediments are weak, it may be necessary to remove the upper layer of the sediment to obtain the required stability for the platform. For instance, at the Tarsiut island location, the weak surficial sediment was removed before the island fill was placed.

4.3.5.11 Permafrost

A layer of permafrost, which may be up to 500 metres thick, exists in the sediments beneath the sea floor of the Beaufort Sea. This was formed thousands of years ago when the shallower parts of the Beaufort Sea were above sea level. When the land subsided and was inundated by the sea, the permafrost started to melt, but since melting takes place very slowly beneath the sea, much of the permafrost still exists (see Volume 3A for more details on permafrost).

The importance of this to the design of offshore production platforms depends on the nature of the subsea materials. Melting of permafrost in clay or silt could cause subsidence. The key factor of concern is the water content of the soil. If the water content is very low, the thawing will likely have a minimal effect on the structure. If, however, the soil has a high water content, thawing of the permafrost could cause slumping of the foundation material and thus, subsidence of the structure.

The only source of heat that could cause melting of subsurface permafrost is that generated in the production wells by the warm oil flowing to the surface. This could cause local settlement of a man-made island, but would probably not be enough to have a detrimental impact. An extensive research and engineering study has been initiated to measure and predict the behaviour and effects of permafrost thawing around well casings used in the Beaufort Sea (APOA Project No. 183). The purpose of the project is to specify appropriate design parameters in order to prevent physical damage of casings, which may affect the integrity of the well during drilling and production at offshore locations. Specific studies within the project include the development of a computer model capable of predicting design parameters for a single-well application; the development of a computer model for predicting design criteria for a typical multi-well application; the development of a computer-based downhole measurement system to gather actual data from the Tarsiut N-44 island well; the taking of a 370 metre, 20 cm core and laboratory analysis of the lithology at the Tarsiut well; and a series of tests to determine the strength of casings and associated connector devices. Measures used to counteract this potential problem are described in Section 4.4.6.1. In addition, it may be necessary to incorporate a system whereby level adjustments for the topside facilities can be made as needed.

4.3.5.12 Earthquakes

The stability of all structures, whether made of steel, concrete or sand, may be threatened by earthquakes and these must be taken into account during design. Under certain circumstances, sand fill islands can liquefy during seismic activity, but the chances of this in the Beaufort Sea are low. Experience to date in the Beaufort Sea indicates that hydraulically placed sands will be stable with regard to liquefaction. Pre-

liminary values for design earthquakes have been calculated and a research project in coordination with the Geological Survey of Canada will develop improved methods of calculating these values (see Volume 7).

4.3.6 BEAUFORT SEA PLATFORM CONCEPTS

Sections 4.4 and 4.5 describe the type of facilities that are required at the oil field site to drill the wells and to process the oil and gas. The civil engineer is presented with the size and weight of the equipment which must be accommodated and the environmental conditions which his structures must tolerate. His assignment is to design a platform for the equipment, which will operate safely throughout the entire producing life of the reservoir. Several possibilities have been explored. These are described in the following sections.

4.3.6.1 Dredged Islands

Dredged islands such as Issungnak (Plates 4.3-23 and 4-3.24) are already tried and proven and most certainly would provide a safe foundation over a long period of time for permanent drilling and producing facilities in shallow water. The permanent island will be provided with slope protection to prevent erosion and would extend further above the surface than exploratory islands, to minimize run-up of waves during fall storms. Slope protection would be provided by rock and gravel or man-made materials.

A future production island in the shallow waters of the Beaufort Sea (0 to 20 m) would likely appear very similar to those being used off the coast of California (Plate 4.3-25). At this particular location (Long Beach), because of the proximity of the islands to the viewing public, they have been decorated to make them more aesthetically appealing. The drilling rigs and production facilities have been covered with facades painted a variety of appealing colours.

4.3.6 Caisson-Berm Island

The caisson-berm island is a variation of the 'sacrificial beach' island such as Issungnak. The caisson-berm island addresses one of the problems that has plagued island builders in the Beaufort Sea for the last several years. Island building has always taken place during the ice-free summer months. The project usually starts in the spring of the year when the ice leaves the construction location, and should be completed in the fall, so the drilling equipment can be placed on the island, followed by drilling during the winter months. The fall of the year, however, is when there are severe and frequent storms, which have not only interruped the dredging operations, but have caused serious erosion problems to islands under construction.

The caisson concept, illustrated in Figure 4.3-12, uses a man-made island or berm which extends from the sea floor to a level about 6 to 10 metres below the sea

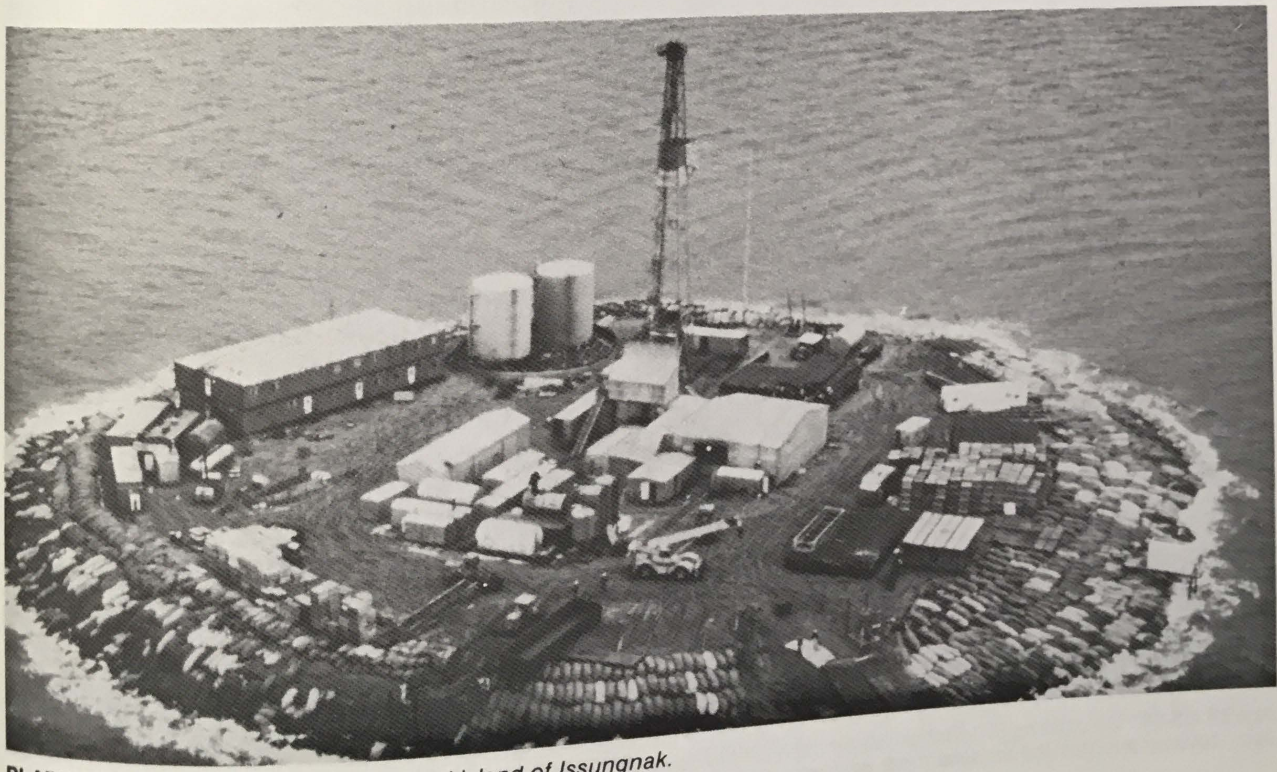

PLATE 4.3-23 *Aerial view of the dredged island of Issungnak.*

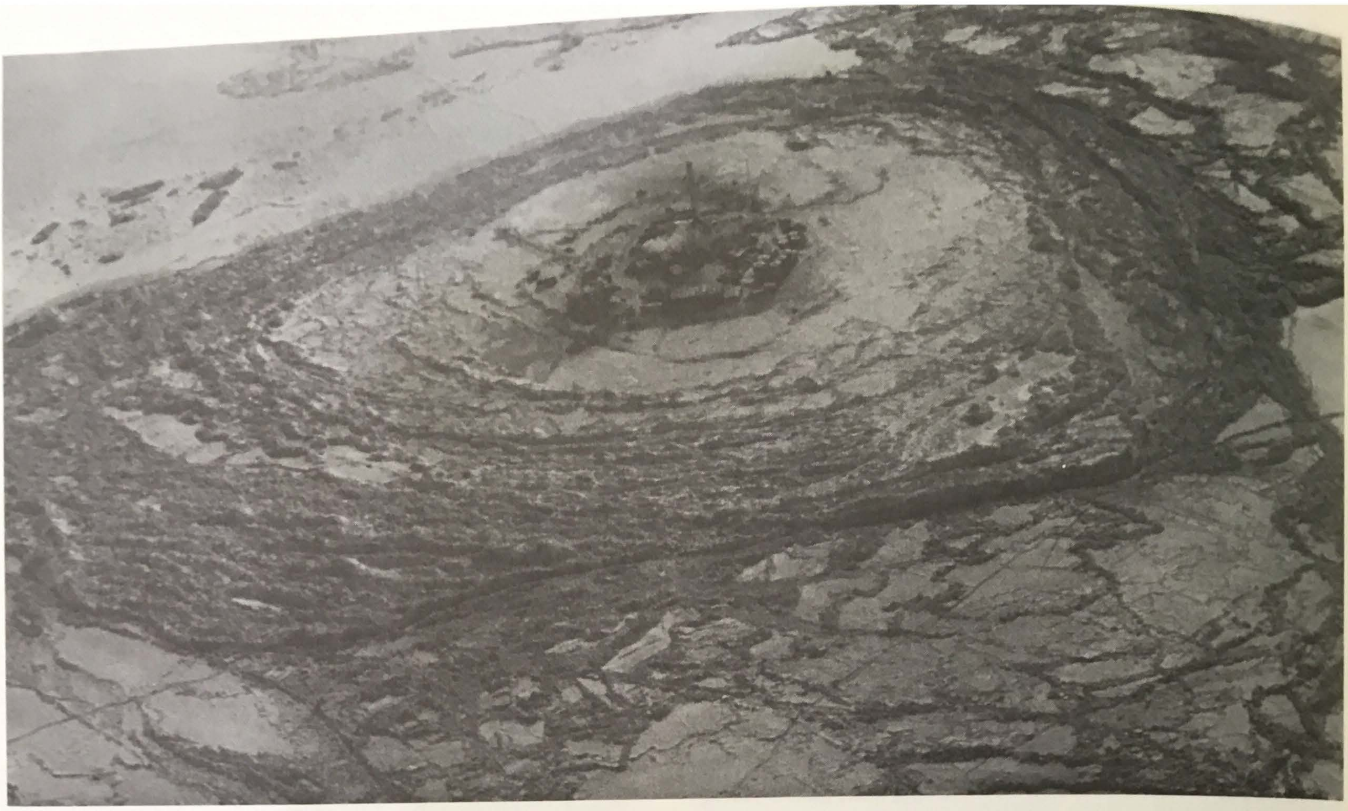

PLATE 4.3-24 *Moving ice runs aground on the beaches surrounding the Issungnak island. A rubble field several times larger than the island gradually builds up. Ice forces are then absorbed by the rubble field rather than the island.*

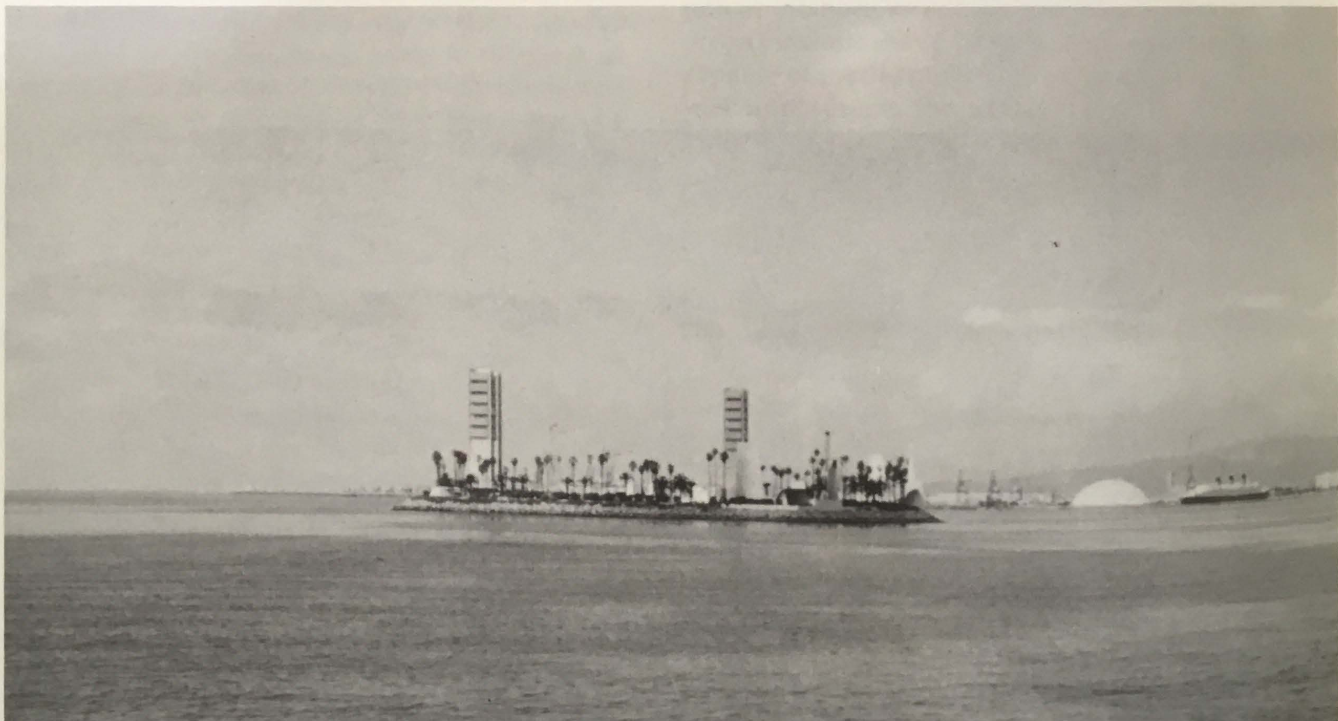

PLATE 4.3-25 *An existing production island used off the coast of California. The drilling rigs and production facilities have been covered and painted to make them aesthetically appealing.*

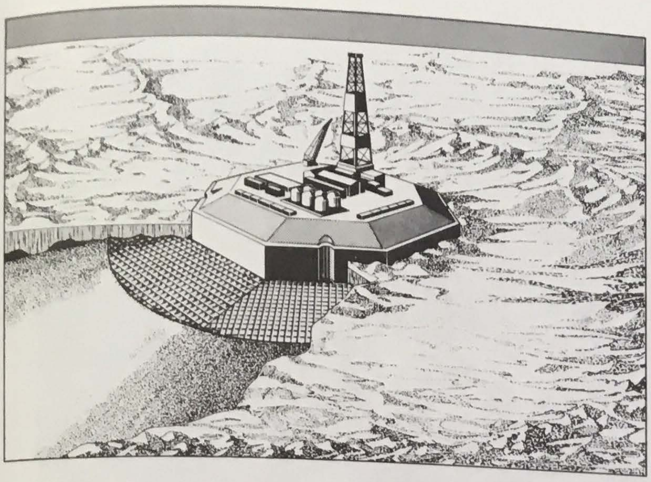

FIGURE 4.3-12 *The caisson-berm island at Tarsiut reduces the quantity of dredged material required and eliminates the problem of wave erosion on the island beaches. The forces of thin first-year ice are absorbed by the caisson. Larger ice features, such as pressure ridges, run aground on the berm before they reach the caisson. This type of island also builds up a rubble field around it during the winter months.*

PLATE 4.3-26 *This photograph taken during the winter of 1981-82 illustrates the interaction of ice with the artificial island at Tarsiut. The Tarsiut island has performed in accordance with expectations and has provided data which will be useful in the design of larger permanent islands. Also shown is the large ice pad, which was built as a relief well drilling pad should it be required.*

surface. Concrete or steel caissons are placed on top of the berm and extend 6 to 8 metres above sea level. The surface of the berm is below the active wave zone so the berm is affected little by wave action. The caissons are floated into place after completion of the berm and can be set in place quickly. The caisson-berm system, therefore, is theoretically much less susceptible to damage caused by fall storms.

The interaction of a caisson island with ice is shown in Plates 4.3-26 and 4.3-27. New first-year ice encountered near the caisson is piled-up around the caissons and grounds on the berm. As the ice thickens, the rubble field begins to grow and becomes larger and larger as the winter progresses. Large pressure ridges ground on the berm so their forces are never applied directly to the caisson. Eventually, a large grounded rubble field forms around the caisson, similar to the rubble field that formed around the Issungnak dredged island.

The caisson-berm type of artificial island could initially be constructed as an exploration platform. If hydrocarbon discoveries demonstrate sufficient reservoirs, production could be undertaken at the site by expanding the island. Figure 4.3-13 illustrates conceptually the expansion of a caisson-berm exploratory island to a production island. The figure also demonstrates the relative sizes of exploratory and producing platforms.

4.3.6.3 Gravity Structures

Figure 4.3-14 illustrates a gravity structure which is somewhat like some of those used in the North Sea. Relying on its own weight to anchor the platform in place, the caisson would likely be made of concrete and would be about 90 metres in diameter at the water level. In this case the ice either fails in crushing or shears and moves around the structure. The advantage of this structure is that it is relatively simple and could be totally fabricated in the south.

The ability of the gravity structure to resist the limit stress forces associated with an ice island interaction is the subject of ongoing studies.

A variation of this concept is to place the gravity structure on top of a dredged berm. This concept is being given serious consideration for production platforms at the deeper water sites in the Beaufort Sea.

4.3.6.4 Monocone Structure

This steel or concrete structure is a variation of the monopod structures used in Cook Inlet, Alaska. The structure is anchored to the sea floor with piling or by its own weight. Its hourglass shape causes the moving ice to 'climb' the structure and the ice fails in bending and moves around the smooth cylindrical surface. Figure 4.3-15 illustrates this structure.

This design can safely resist most of the ice forces which could be exerted upon it by ice features in the Beaufort Sea. However, its resistance to loads from a large ice island is questionable. If one is faced with the probability of being hit by an ice island at a particular site, the provision of a protective subsea berm would be required. It should be mentioned that a collision with an ice island is something that could be predicted many days or even months ahead of the event since the ice moves very slowly. Thus, the failure of the structure would not cause any environmental degradation since all of the wells would be safely

PLATE 4.3-27 *A rubble pile formed around the Tarsiut Island in early winter.*

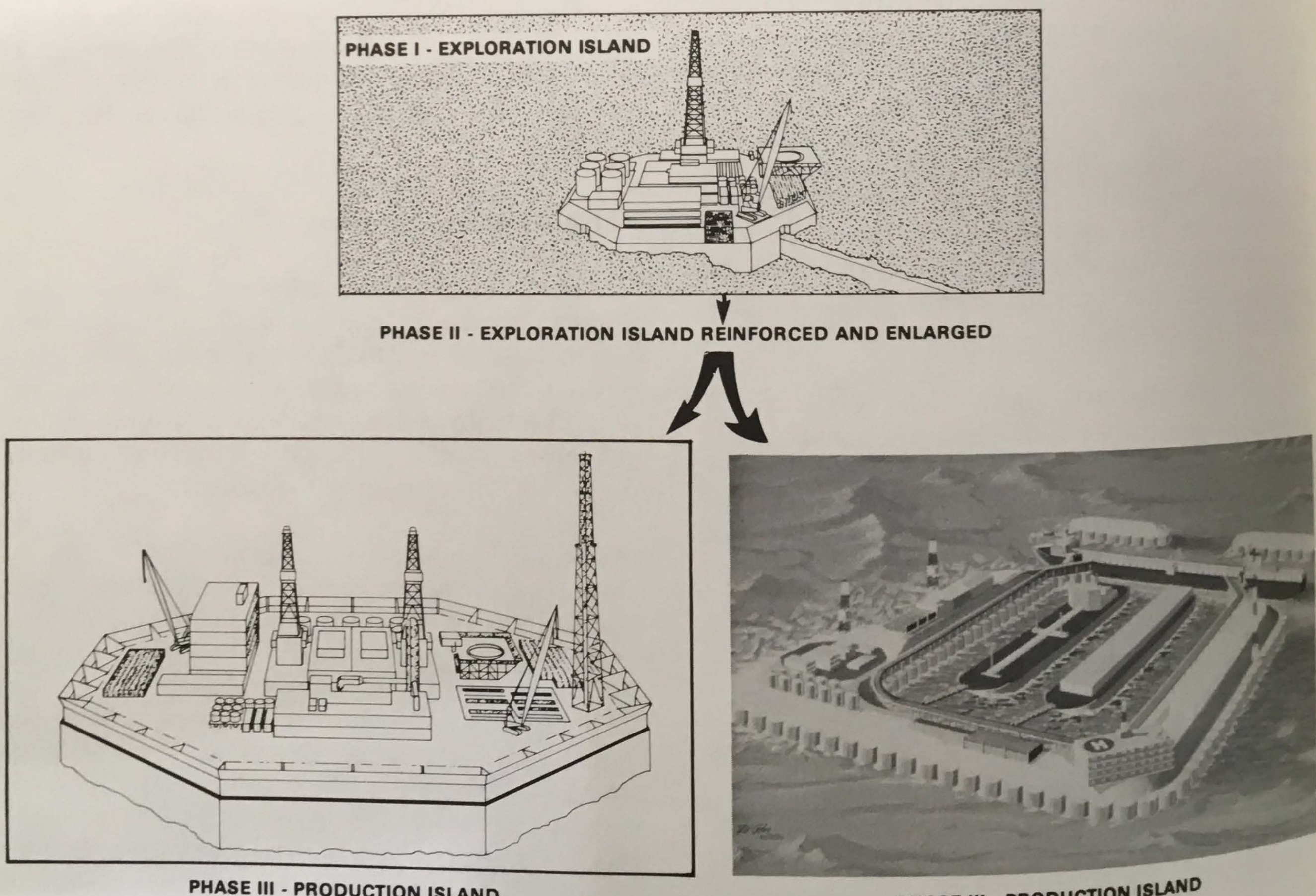

FIGURE 4.3-13 *An exploratory island such as Tarsiut could be expanded into a larger permanent production island by additional dredging and the installation of additional caissons.*

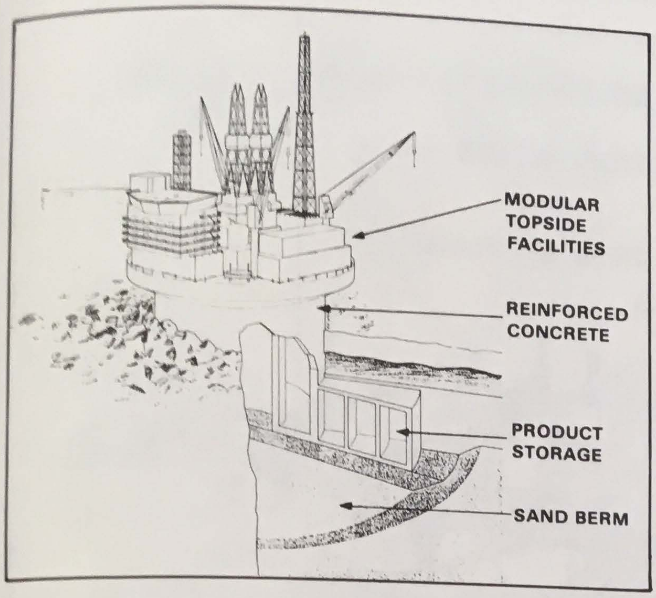

FIGURE 4.3-14 *Other concepts for permanent production foundations in the Beaufort Sea include a concrete gravity structure placed on the sea bottom. This is similar to gravity structures being used in the North Sea.*

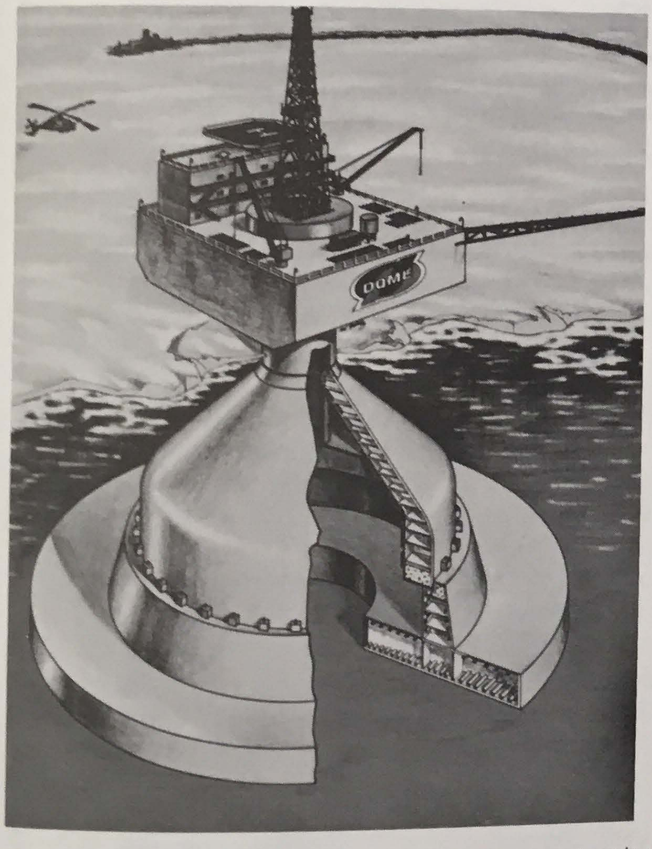

FIGURE 4.3-15 *Another variation of a gravity structure is a monocone, similar to the monopod used in Cook Inlet, Alaska.*

secured and personnel evacuated. Naturally there could be a large financial loss. Figure 4.3-16 illustrates the forces which may act on a monocone during the winter.

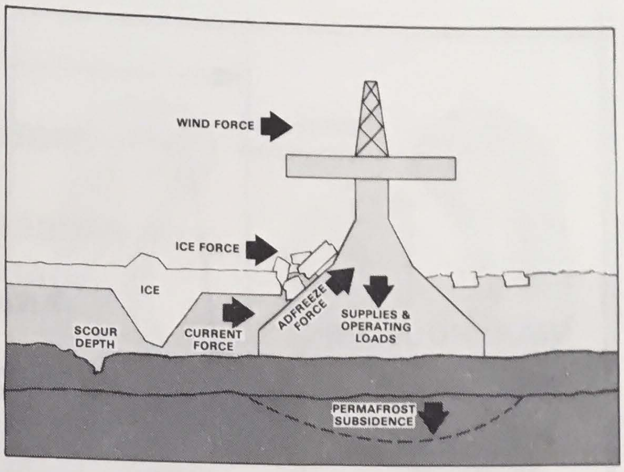

FIGURE 4.3-16 *Platforms must be designed for wind forces, ice forces, wave and current forces, ice freezing to the structure, and for the weight of equipment and material.*

4.3.6.5 Arctic Production and Loading Atoll (APLA)

The island building technology developed during the past several years in the Beaufort Sea illustrates the feasibility of building islands even in deep water. The largest concept for offshore platforms is illustrated in Figure 4.3-17 and is called the Arctic Production and Loading Atoll (APLA). One older concept for an APLA is a two island system, with the two portions of the island forming a protected harbour or lagoon.

The islands are built to withstand the maximum ice forces that can be exerted in the Beaufort Sea. These are the forces associated with ice islands. Such an ice feature would be resisted by the submerged berm.

The inside lagoon, like any harbour, provides protected water in the summer months and may be covered with fast ice in the winter months. The inside of the lagoon then becomes a well protected harbour where a variety of platforms could be used to accommodate drilling and producing equipment platforms are shown in Figures 4.3-18, 4.3-19 and 4.3-20.

Figure 4.3-18 illustrates the system where the berm has been extended so that the drilling and producing facilities can be mounted directly on the island surface. This system would be similar to that illustrated previously on a production island. This type of system, however, would enable the designer to spread out the equipment more than on a production island, since additional surface area could be provided at a nominal cost. One might have two or three such systems in order to provide additional drilling and producing capabilities.

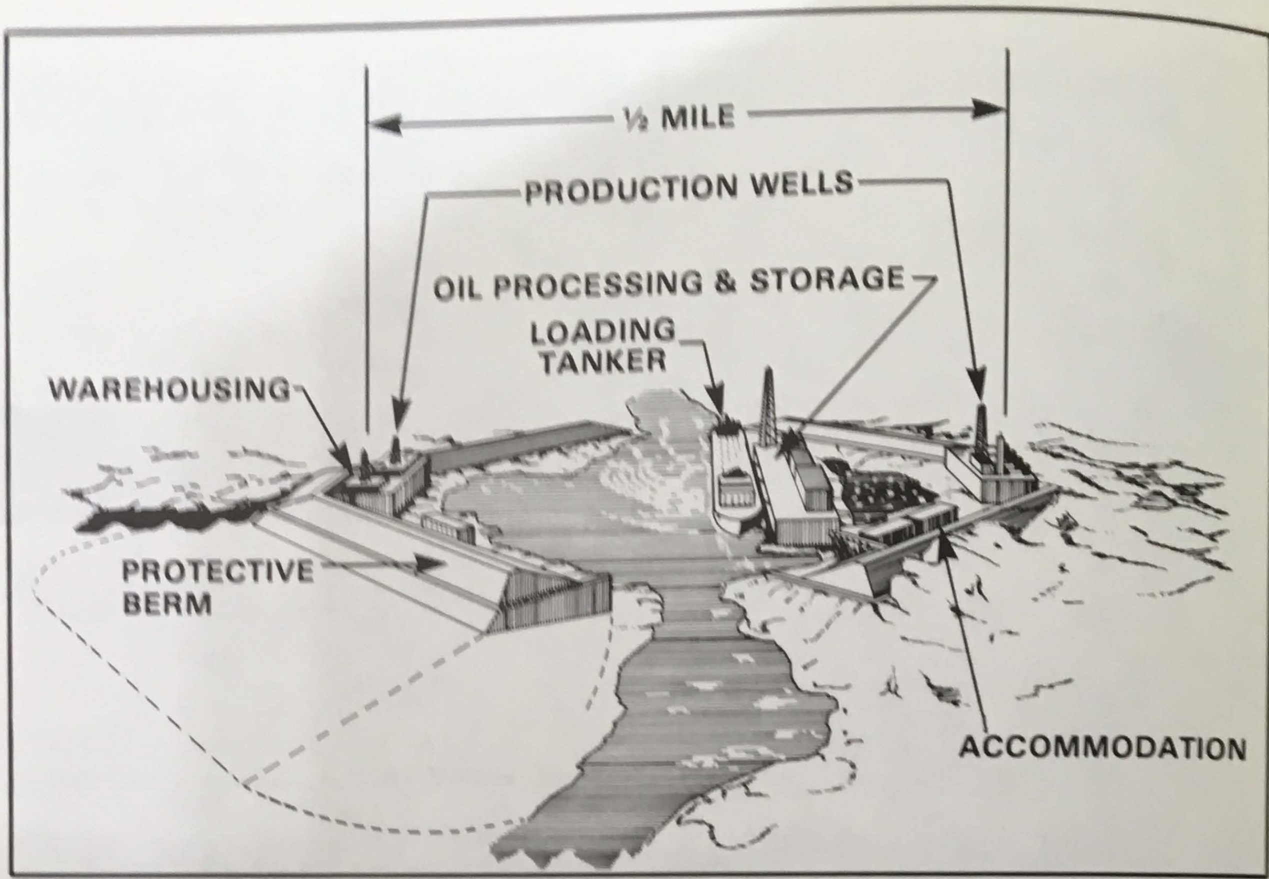

FIGURE 4.3-17 *One variation of a production processing and loading terminal is known as an APLA (Arctic Production and Loading Atoll). The two crescent shaped islands provide protection from the moving ice for the drilling, producing, loading and storage facilities.*

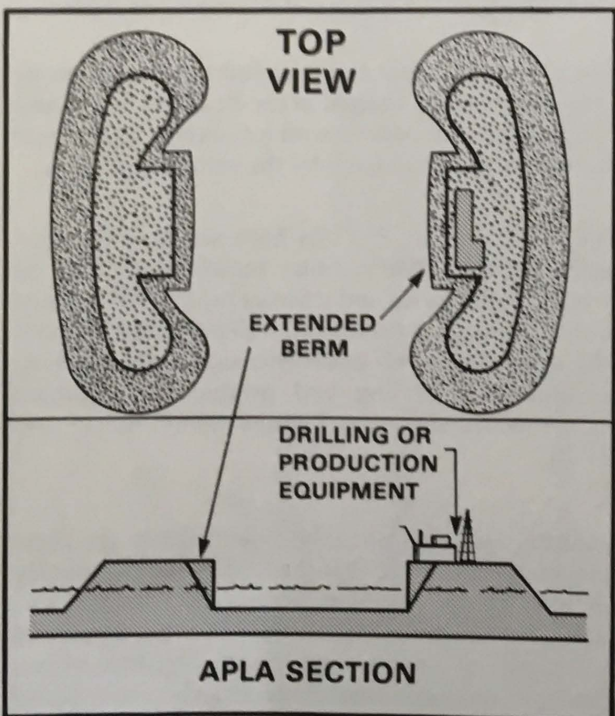

FIGURE 4.3-18 *An APLA provides sufficient berm surface so that drilling and producing facilities could be placed directly on top of the berm.*

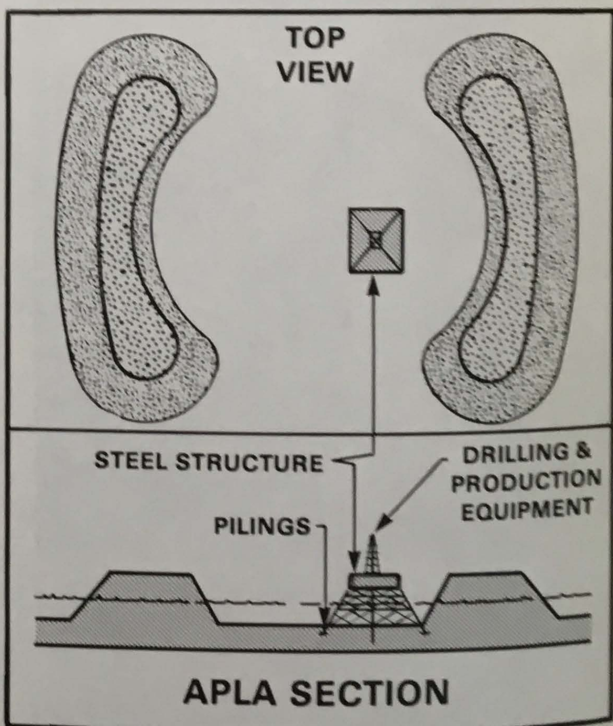

FIGURE 4.3-19 *An alternate to placing drilling and production facilities on the berm is to install them on conventional steel jacket platforms, anchored to the sea floor, with piling. The berm protects the structure from moving ice.*

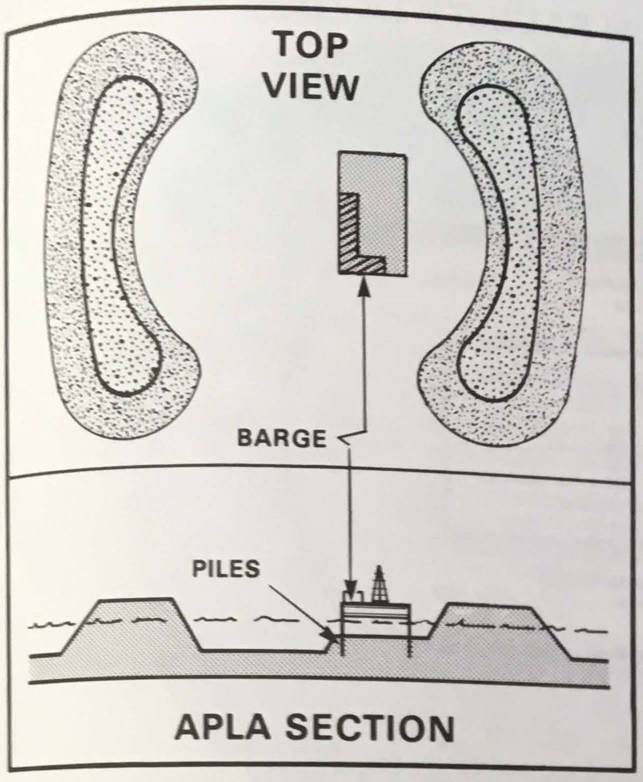

FIGURE 4.3-20 *Drilling and producing facilities could be floating systems permanently moored within the protected harbour of the APLA.*

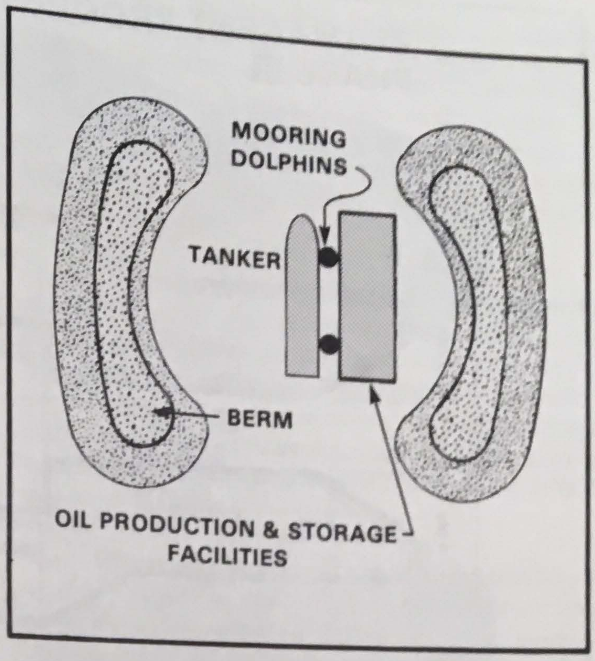

FIGURE 4.3-21 *Within the harbour of an APLA, the Arctic tankers will moor at fixed mooring dolphins and crude oil will be transferred from storage facilities.*

Figure 4.3-19 illustrates a steel platform system which is anchored to the berm and sea floor with steel piling. This type of platform would be similar to that used elsewhere in the world, since it is no longer required to withstand massive ice forces. Again, several structures of this type could be located within the protected lagoon.

Figure 4.3-20 shows a floating system of drilling and producing systems within the APLA harbour. Floating systems would be built on large barges in the south and floated to their location inside the lagoon of the APLA. The barges would be securely moored, probably with piling driven into the berm through the four corners of the barge. Producing wells could be drilled using either subsurface systems like those for exploratory wells, complete with subsurface well heads, or with surface type systems like those used on jack-up drilling units. Several such floating units could be placed inside the lagoon.

The key component in the APLA system is a facility for storing produced oil and loading the icebreaking tankers that will carry the oil through the Northwest Passage to southern markets. Figure 4.3-21 illustrates one type of system which might be used. It includes a fairly standard system of mooring dolphins where the tankers would be secured during loading. A floating storage system would be located in the vicinity. Oil would be produced from the producing wells, processed within production facilities, transferred by underwater pipeline to the storage barge, and then pumped from the storage barge into the waiting tankers. The volume of storage required would likely be at least twice the volume of a tanker, or about 500,000 cubic metres.

Alternate design concepts for an Arctic Production and Loading Atoll are shown in Figures 4.3-22 and 4.3-23. These concepts provide a protected harbour for the location of floating production units and crude oil storage, and for mooring the Arctic tankers while loading, and provides space on the berm for drilling systems, consumable storage and accommodation facilities. The relative size of the Tarsiut artificial island is shown in Figure 4.3-22 to demonstrate the size of the APLA at the surface.

The construction procedure for building an APLA is identical to that used for building an island like Tarsiut. First, the subsurface soil characteristics are measured over a wide area by taking multiple cores, a few hundred metres deep. All of the characteristics of the soil are determined in the laboratory as they are for any major civil engineering project. If sand or gravel is the predominant material on the sea floor then little or no preparatory work would be required. If clay or silt is present, it may be necessary to remove enough of the soil to ensure that the resulting base would have adequate bearing strength. The APLA would then be built from granular material, dredged from borrow sites as near as possible to the APLA site.

The type of dredges used would be dependent on the water depth of the APLA, the distance to the borrow

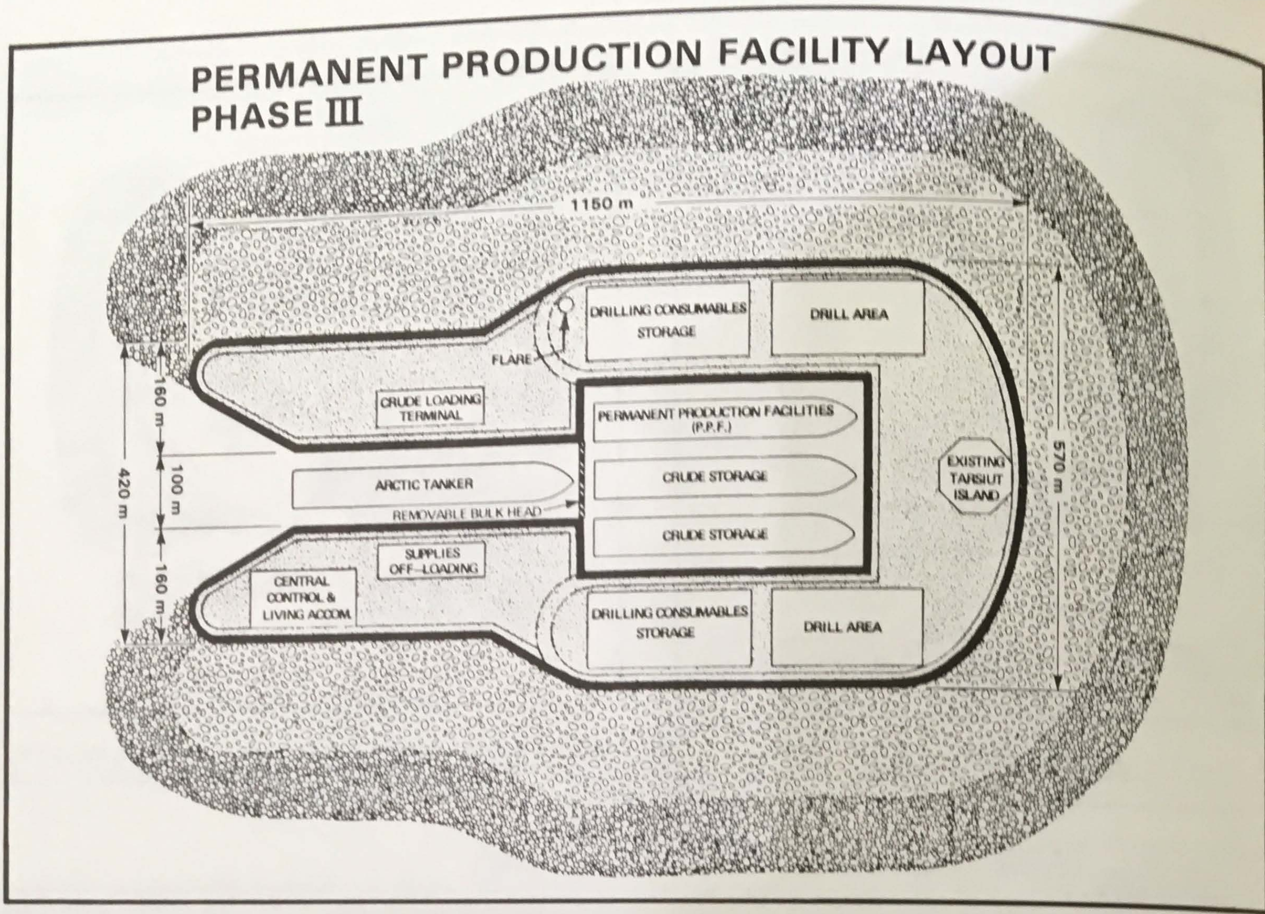

FIGURE 4.3-22 *Reducing the size of the APLA produces a horseshoe shaped island as shown in this illustration. This island has sufficient strength to resist the highest ice forces in the Beaufort Sea while at the same time accommodating all of the facilities required to drill, produce, process, store and load crude oil. There is sufficient waste heat from the production process to control the ice thickness in the centre part of the island.*

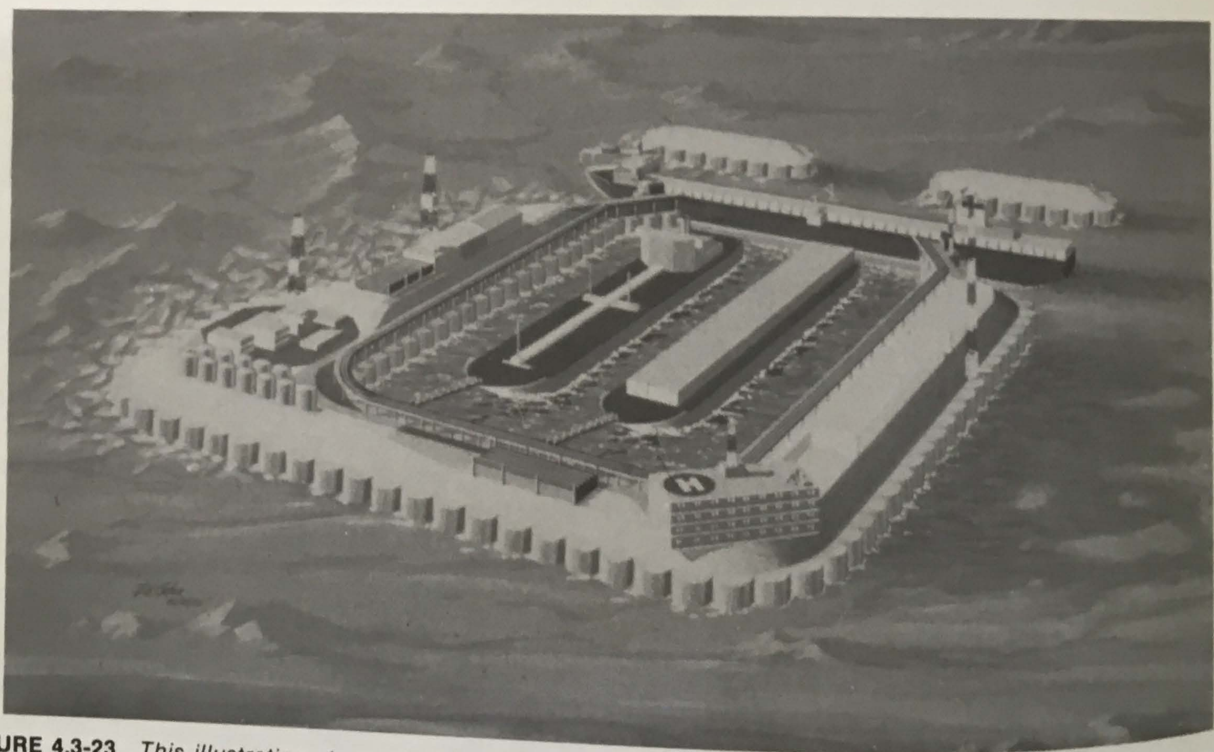

FIGURE 4.3-23 *This illustration shows an alternative shape for a reduced size APLA. The construction procedure for building an APLA is identical to that used for building an island like Tarsiut. First, the subsurface soil characteristics are measured over a wide area by taking multiple cores, a few hundred metres deep. All of the characteristics of the soil are determined in the laboratory as they are for any major civil engineering project. If sand or gravel is the predominant material on the sea floor then little or no preparatory work would be required. If clay or silt is present, it may be necesary to remove enough of the soil to ensure that the resulting base would have adequate bearing strength. The APLA would then be built from granular material, dredged from borrow sites as near as possible to the APLA site.*

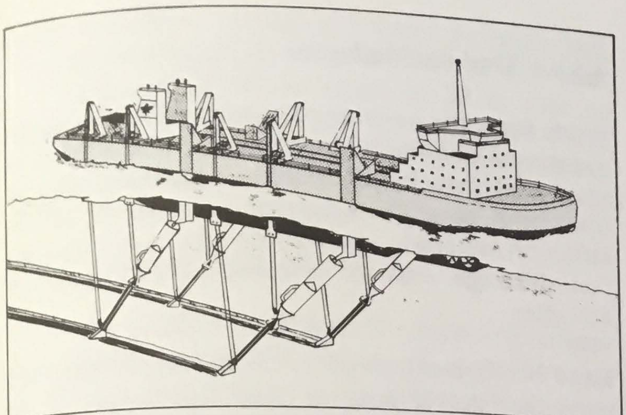

FIGURE 4.3-24 *Dredges will play an important role in the construction of production islands. The special Arctic dredges which will be able to operate in ice and in deep water have been fully designed. These would be the largest dredges in the world. Material would be dredged from the sea floor at appropriate sites where gravel or sand is present and transported to the site where an island is being built.*

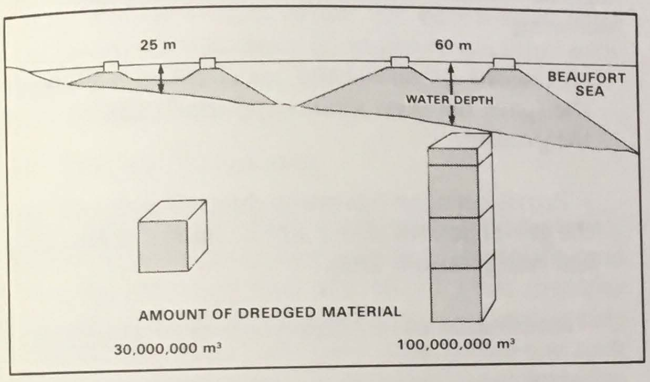

FIGURE 4.3-25 *The quantity of dredged material required for the construction of an APLA increases considerably with water depth.*

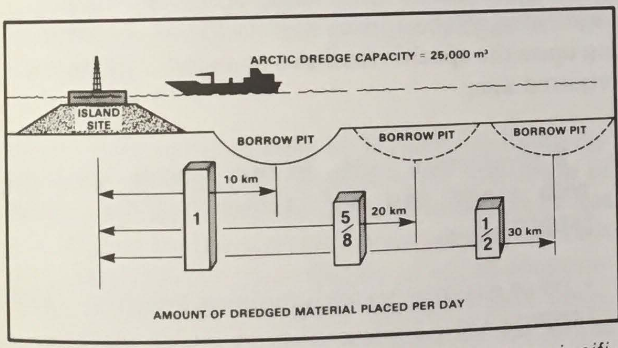

FIGURE 4.3-26 *The distance to the borrow pit is a significant factor in planning for the construction of large offshore sand structures. The daily capacity of an Arctic dredge is reduced by 50% when the borrow pit is 30 km from the construction site compared to 10 km.*

site, and the time allocated to build the APLA. Two to three working seasons is a reasonable time period for building the berm portion of the island. If an APLA were eventually built at a site like Kopanoar, approximately 100 million cubic metres of material could be required and a quantity of clay may first have to be removed from the site. This work would require specially designed dredges because of the water depth and the long haul from likely borrow sites. These dredges (Figure 4.3-24) have already been designed and are described in Section 5.1. Special features of these dredges include the capacity to haul 25,000 cubic metres of material (about 2.5 times larger than the largest hopper dredge in the world), an icebreaking hull so that the dredge could operate for an extended season in the Beaufort Sea, and a very long stinger so that the dredge can remove clay at sites like Kopanoar.

In the case of Koakoak, the dredging requirements are considerably less because the water depth is less (47 metres) and because the location is much closer to suitable borrow areas. It is possible that stationary suction dredges, in combination with conventional trailer suction hopper dredges such as those used to build the Tarsiut Island, could complete an APLA system at Koakoak.

If an APLA were placed at Uviluk, the construction activities would be less extensive due to the shallow water depth (30 metres) and the proximity of suitable borrow material. Stationary suction dredges, such as the BEAVER MACKENZIE, or a cutter suction dredge, such as the AQUARIUS illustrated in Plate 4.3-28, would likely play a key role in building an APLA at Uviluk.

Figure 4.3-25 illustrates the volume of material that is projected to be required for an APLA as a function of water depth. Figure 4.3-26 illustrates the capacity of an Arctic dredge on a daily basis as a function of haul distance. By combining the information in these two graphs one can determine how many Arctic dredges may be required to build an APLA in any water depth at any location in the Beaufort Sea.

PLATE 4.3-28 *The AQUARIUS is a cutter suction dredge that has been working in the Beaufort Sea since 1979. This dredge cuts a channel in the sea floor and pumps the dredged material through a pipeline to the island location.*

4.3.7 OPERATION, MAINTENANCE AND ABANDONMENT

Maintenance of onshore platforms for drilling and production will be limited to ensuring that permafrost below the gravel pads remains in the frozen state. Although not expected to be a problem, the condition of the permafrost adjacent to production wells will be monitored in order to provide an early warning of increasing soil temperature (see Section 4.4). If required, the permafrost insulating system will be modified to ensure the integrity of the platform.

Abandonment of onshore exploration drilling platforms has been discussed in Section 4.3.1, and abandonment of production platforms onshore will normally be the same. A reclamation program will be developed for each location on a site specific basis and will include sealing of the wells, removal of the topside equipment for use elsewhere or for transport out of the region as scrap. The gravel pad may be removed for use elsewhere if economically feasible, or the gravel will be incorporated into the overall site reclamation plan.

When construction of an offshore drilling or producing island, or APLA is complete, maintenance will be primarily related to replenishment of berm materials or erosion protection measures as required. The effect of ice conditions on the structures, and the continued ability of the island to safely withstand ice forces and other environmental factors will be monitored.

Abandonment procedures common to all offshore platforms include sealing the wells and removal of topside equipment. Further procedures are a function of many factors including type of structure, the design life of the structure, the potential alternate uses of the site, economics and environmental concerns. Unless the need for sand in the region can economically be met by dredging sand from an abandoned artificial island, the sand berm will be left and will gradually be eroded by the action of wind, waves, currents and ice. Deep water caisson drilling systems like the Caisson Retained Island will be towed from a completed site to a new drilling site. Reclamation plans for gravity type platforms, caisson-berm islands and other large offshore platforms will be formulated on a site specific basis.

4.3.8 POTENTIAL ENVIRONMENTAL DISTURBANCES

This section identifies likely or potential environmental disturbances from onshore and offshore platforms. Volume 4 addresses the environmental interactions in detail.

4.3.8.1 Onshore Platforms

Aside from the possible environmental disturbances associated with the facilities themselves, the potential sources of disturbance of onshore platforms are land utilization, permafrost degradation, securing of construction materials, alterations to the terrain and surface drainage, and the construction and operation activities.

Land-based installations in the Mackenzie Delta will use either gravel pads or platforms supported on piles. The specific design for foundations and pads will be determined using site specific geotechnical data including subsoil and permafrost information.

The need for cooling systems to minimize permafrost degradation may require the use of one or more of the following:

- Assisted or unassisted air circulation through the space between a pile supported platform and the ground,

- Provision of refrigeration ducts or piping within the gravel pad for either air circulation or mechanical refrigeration, and

- Installation of insulation within the gravel pad.

Before construction of an onshore platform can begin, the site will be properly prepared by installing gravel pads and by controlling drainage. The area to be affected will be approximately 10 to 15 ha, depending upon the specific facilities installed. Typical areas required are:

- 8 production wells, in two clusters, complete with sumps and fuel storage facilities - 5 ha (approx.)

- oil or gas treating and compressor facilities - 4 ha (approx.)

- airstrip (STOL) or heliport - 2.5 ha (approx.)

- temporary construction camp - 3 ha (approx.)

Total approx. area = 14.5 ha

Mitigative measures will be utilized to ensure adequate storm drainage, stability of slopes and prevention of permafrost degradation.

About 225,000 m^3 of gravel is required to provide a base for a 15 ha site. In borrow areas where the gravel is deep, the land area disturbed will be equivalent to the area of the terrestrial platform, or approximately 15 ha per platform. However, in areas where depth of

gravel is shallow, upward of 3 times an equivalent area may be affected, or 45 ha. Combined with haul roads, typically 30 km in length by 15 m wide or occupying 40 ha, the total land area impacted could amount to 85 ha per platform. If the borrow pit is too shallow, alternative sources of gravel from distant borrow pits or ocean dredging will be used.

4.3.8.2 Offshore Platforms

All of the proposed offshore production platform types present a potential source of environmental disturbance, be it as a result of physical activity associated with construction and operations, or due to its physical presence. Common to all platform types is the local effect on ice dynamics in the vicinity of the structures and the possible long-term, but local, alteration of physical oceanographical parameters as they are constructed. The sand constructed platforms, and to a lesser extent the concrete or steel structures, will also have an impact associated with dredging.

(a) Dredging Disturbance

Artificial islands are to be constructed with materials from three primary sources: granular material dredged from the sea floor near the island sites; granular material dredged from marine areas considerably removed from island sites; and sand, gravel and rock mined from borrow pits onshore and transported to the island sites either by trucks on the winter ice or by barges in summer. Most island construction materials, however, are dredged from the sea floor using suction-type dredges, and these activities are the focus of this discussion.

The most immediate source of disturbance by dredging on the physical environment is the alteration of bathymetry. The dredged depth will normally be less than 20 m. It is expected that construction materials will be dredged as close to the site of island construction as possible to minimize transportation costs. Some of the future dredges designed for use in the Beaufort Sea may be capable of operating in water depths of up to 80 m.

The placement of dredged materials will result in the dispersion of fine particles into the surrounding sea water. The effect of dispersion is a localized increase in turbidity and suspended solids, a decrease in dissolved oxygen levels, and possibly nutrient enrichment. Short-term dredging-related variations in vertical temperature and salinity stratification have also been documented. All of these effects of dredging will be short-term, corresponding only to the duration of dredging activity. These effects will be most pronounced during freeze-up when background turbidity is typically lower. Inside the Mackenzie River plume the effects of dredging are not easily distinguished from background turbidity levels during much of the open water season.

(b) Platform Construction

The sources of disturbance for artificial island construction may include: the removal of seafloor material and its deposition at another location to clear a site for the foundation; pile driving; the excavation of a borrow pit; materials transport and placement; and related activities.

Where the seabed at the construction site consists of unacceptable foundation materials, the soil may be removed by dredging to the appropriate depth. The material removed, called dredge spoil, will be deposited at approved locations adjacent to the construction site.

Table 4.3-2 provides approximate dredged volume requirements and estimates of the area of the sea floor which will be disturbed for shallow and deep production platforms and for APLA's constructed in shallow and deep water. Shallow platforms are those built in water less than 20 m deep and deep platforms are those built in water ranging from 20 to 60 m deep.

TABLE 4.3-2

APPROXIMATE DREDGED VOLUME REQUIREMENTS

Type	Base Diameter m	Dredged Quantity m^3	Affected Area* m^2
Shallow Island	800 m	10×10^6	1.5×10^6
Deep Island	1200 m	40×10^6	3.5×10^6
Shallow APLA	1100 m	30×10^6	2.7×10^6
Deep APLA	2500 m	100×10^6	11.25×10^6

*Includes: borrow pit, base of island, area of deposition of dredge spoil.

(c) Superstructure Construction

Islands in shallow water (less than 20 m) may not require a prefabricated superstructure. For islands in deep water, however, caisson-like superstructure modules may be required. These units would be prefabricated in southern sites and transported to the construction site for installation.

The main sources of disturbance due to construction of the superstructure of the platform will include towing of prefabricated modules to the site, installation of the modules, dredging to supply materials to anchor the superstructure and to provide ice protection, and island surface preparation. The physical presence of the superstructure also represents a source of disturbance to the local physical oceanographical regime.

Platform dimensions and the physical quantities of dredged material used in superstructure construction are included in the foregoing table.

(d) Maintenance Dredging

Maintenance dredging may be required from time to time to replace sand lost to erosion by ice, waves, and currents.

Annual materials lost to erosion are estimated at approximately 2% of the in-place volume. The same borrow pit may be used every year to obtain the necessary materials and could be located as far as 100 km from the platform.

(e) Artificial Island Operations

When completed, the island acts as a physical barrier to both marine traffic and to local ocean currents and ice movements.

Production platforms built near the edge of the landfast ice may result in the localized extension of the landfast ice edge to the platform. Islands such as Uviluk, which will be located up to 20 km beyond the landfast zone, will be situated in the transition ice zone, which separates the polar pack ice from the landfast ice. There is presently no reason to believe that the landfast ice edge would extend out this far, since naturally occurring grounded rubble formations in the transition zone have been observed to have no effect on landfast ice extensions. More information on this and other subjects raised is presented in Volume 4.

Ice pile-up around artificial islands has been described in Section 4.3.5.3. Although there is considerable information on the mechanisms of pile-up, there is little on the possible effects of this pile-up on regional ice dynamics. This latter effect may be an ice related impact concern. The extent of ice pile-up around offshore platforms will vary considerably, depending on location and on weather conditions in any particular season. It is predicted from the existing data base that ice pile-up against production platforms could reach a vertical height of approximately 11 metres maximum, average approximately 3 metres, and could extend over an area approximately 3 times the cross-sectional area of the structure where it intercepts the waterline. This phenomenon appears to be reasonably constant irrespective of the size of the structure or its water depth.

Free ice on the surface of the sea will accumulate in and around the harbour of an APLA and must be removed or reduced in thickness to allow tankers to enter the harbour. This can be accomplished by using waste heat to melt the ice, with or without barriers, and insulating materials.Typical sources of waste heat which would be employed for this purpose include turbine exhaust heat and cooling water.

Where thermal discharges are used for ice management, the discharge water temperature would be in the range of 4°C to 8°C. In contrast, during most of the year, the temperature of Arctic waters remains below 0°C. In the summer, the surface temperatures may reach a maximum of 5°C, with deep water remaining at 0°C. It is assumed that on the average, waste heat releases will enter the water just below the ice at 6°C above ambient.

4.4 DRILLING SYSTEMS

Wells are drilled for a number of reasons during the exploration and development of oil and gas resources. Exploration wells are the most important component in the discovery of oil and gas, and are drilled at locations and to depths predetermined by seismic and other geologic information. Delineation wells are drilled to determine the size of a discovery and to provide data for use in designing hydrocarbon recovery systems.

Production wells are drilled and operated at locations in an oilfield that will efficiently drain the oil from the reservoir. In the Beaufort Sea-Mackenzie Delta Region, most of the production wells will be drilled directionally (up to 60° from vertical), enabling many production wells to be drilled from one platform. Also, injection wells will be drilled to reintroduce produced water and gas to the formation.

The procedures and equipment used to drill the various types of wells are essentially the same and, for the purposes of this section, drilling is described in the general sense.

4.4.1 TYPES OF DRILLING SYSTEMS

Four basic types of drilling systems will be used in the Beaufort Sea-Mackenzie Delta Region: the conventional land rig similar to systems used in Alberta; the specially designed 'platform type' rig similar to systems used on offshore platforms in the North Sea and elsewhere; the drillship currently used in the Beaufort Sea and in other offshore areas; and the conical drilling unit that is currently being designed for the

Arctic. Although the basic drilling components of all these systems are the same, they are assembled differently to take advantage of certain conditions or to cope with anticipated problems. These drilling systems are illustrated in Plates 4.4-1, 4.4-2 and 4.4-3 and Figure 4.4-1.

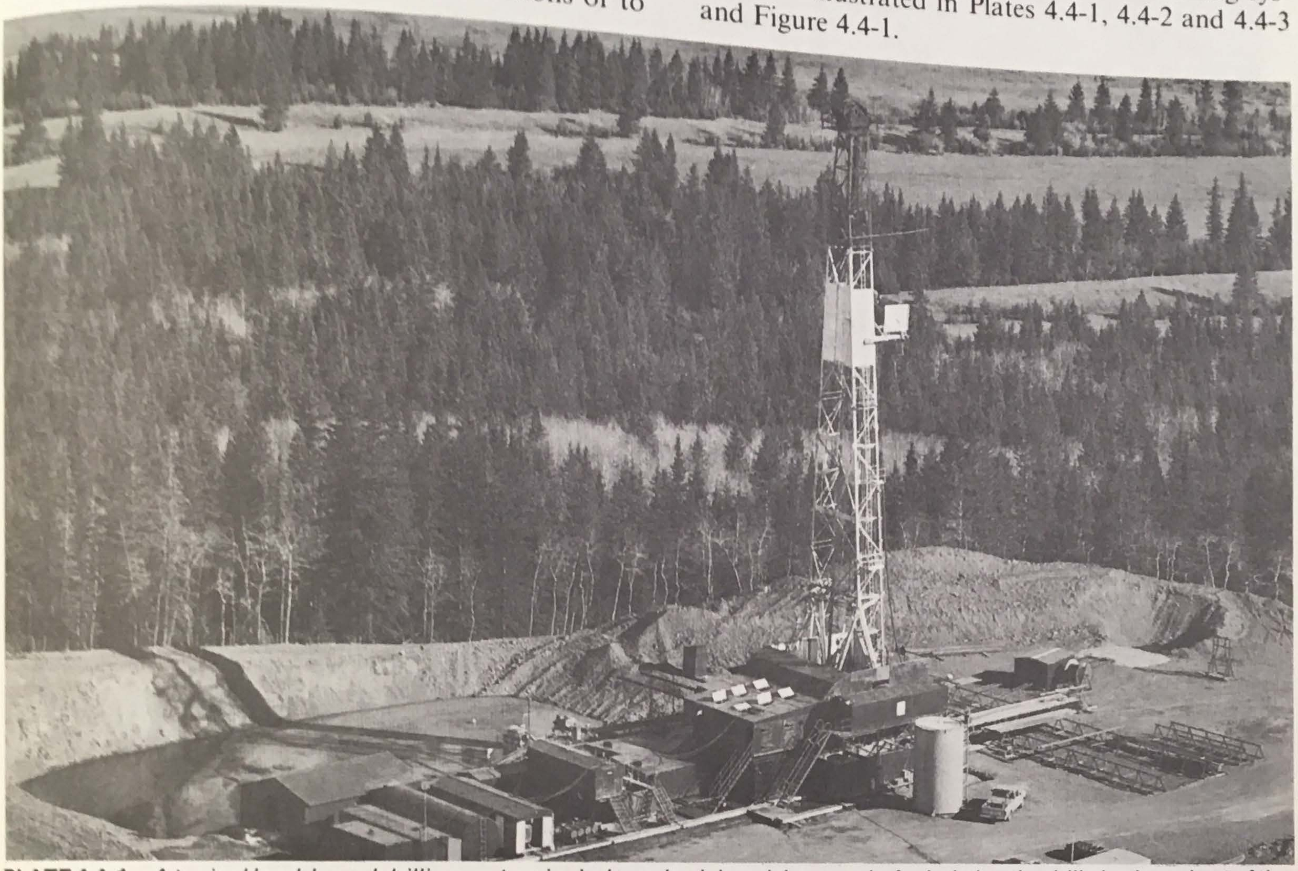

PLATE 4.4-1 *A typical land-based drilling system includes a derrick and draw works for hoisting the drill pipe in and out of the hole, a mud system for pumping mud down the inside of the drill string to lubricate the bit, carrying drill cuttings to the surface and control well pressures, and support systems such as electrical power, heat and accommodations.*

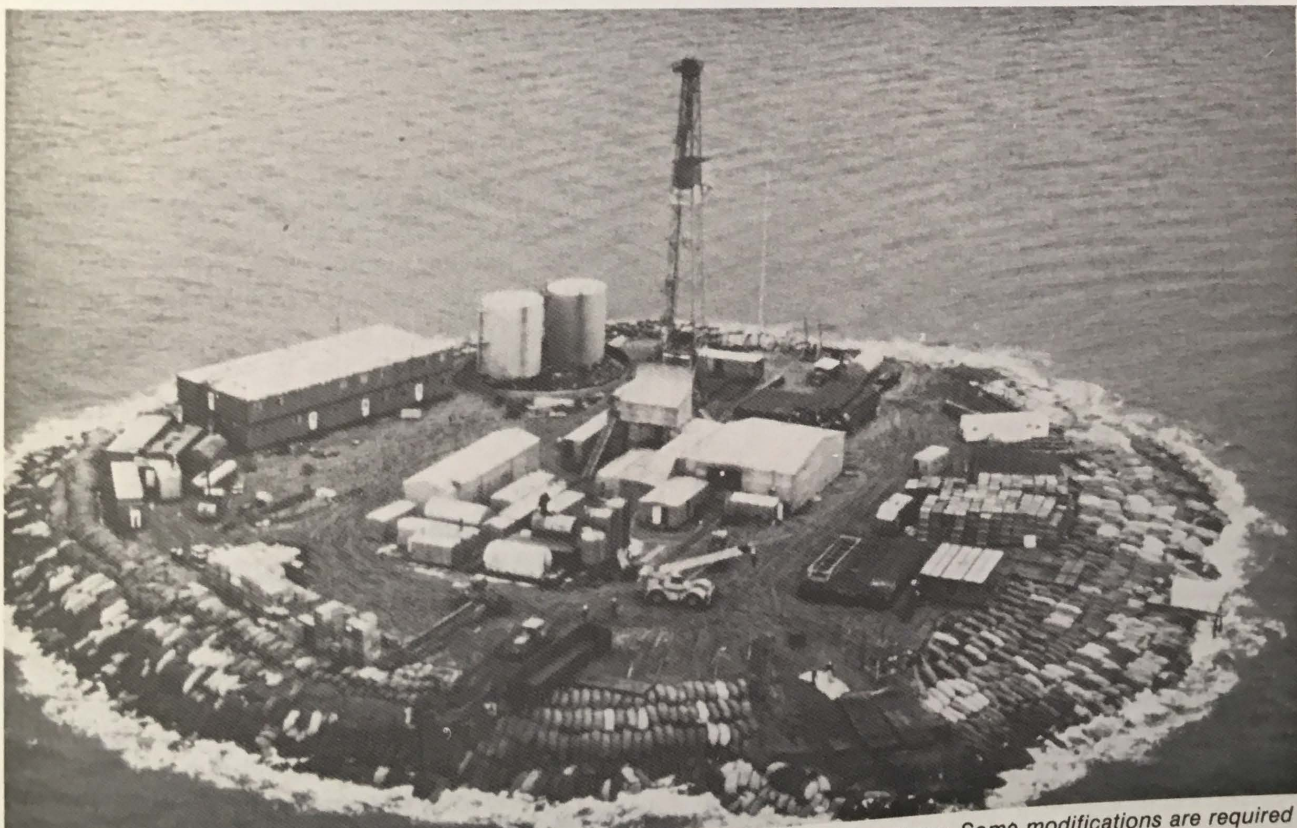

PLATE 4.4-2 *Drilling systems used on artificial islands are conventional land systems. Some modifications are required because of the smaller surface area available.*

PLATE 4.4-3 *Drilling systems used on offshore floating vessels are also very similar to conventional land systems. They are modified to accommodate the motion of the vessel and arranged to accommodate the vessel configuration.*

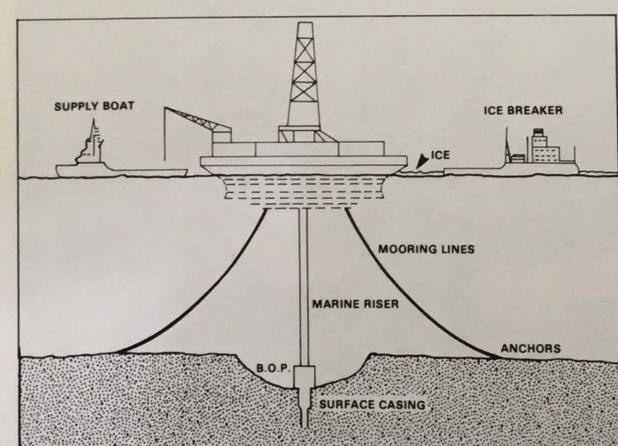

FIGURE 4.4-1 *The conical drilling unit is a specially designed Beaufort Sea exploratory drilling system which has an icebreaking bow around its entire periphery. Its resistance to the ice is therefore similar to that of the bow of an icebreaker and enables it to work in much thicker ice than a drillship can.*

With all the drilling systems, the working areas are heated and protected against the extreme weather conditions that are encountered. The platform type drilling system used on an artificial island will differ from the conventional land system only in the greater use of equipment modules to conserve land area. Modules may be stacked on more than one level to reduce space required, while still retaining efficiency.

Although the basic components of a floating drilling system are the same as other types of drilling systems, the arrangement of the equipment differs in some important ways. The most important is the location of the blowout preventer, which serves to stop accidental releases of hydrocarbons from the well. This device is located at or below the sea floor and is designed to permit quick disconnection by the drillships. In addition, the marine riser, which is the pipe connecting the drilling equipment on the ship to the blowout preventer, is flexible to compensate for vertical and horizontal movement of the vessel. The

equipment that provides these features is complicated but well proven and reliable.

4.4.2 THE DRILLING PROCESS

Early wells were drilled in the oil industry using cable tool rigs. These rigs, used by water well drillers, establish a hole by moving the bit up and down at the end of a cable. The drilling action took place by a pounding and twisting action. The industry quickly outgrew this type of drilling system because of its depth limitations. It was replaced by the rotary system of drilling.

The four main components of the rotary system are the drill bit, the drill pipe or string, the hoisting system and the mud system. Figure 4.4-2 shows the drilling system components. The rotating action of the drill bit chips away the pieces of rock. The bit is attached to the drill string, a hollow pipe which is rotated by a mechanical system on the surface. Fluids, called drilling mud, are pumped down the inside of the drill string during the drilling operation. The drilling mud passes through holes in the bit, to keep the bit clean, provide lubrication and carry material, cut by the bit, back to the surface. The drill string is suspended from a derrick and can be run in and out of the borehole hole with the hoisting equipment.

During the sixty years that the oil industry has been drilling holes using rotary drilling techniques, a set of good operating practices has been developed which provides guidance for the engineer in selecting equipment, and for the drilling crew in operating the drilling system. This experience is and will continue to be used to avoid problems in the Beaufort Sea - Mackenzie Delta drilling program, and to ensure that preparations are made to cope with the unexpected. In addition, there are comprehensive regulations in Canada, governing drilling in all frontier areas, that give legal status to good practices and prevent the taking of short cuts. These regulations are considered to be the most comprehensive and stringent of any drilling regulations in the world.

Although drilling consists of simple processes, the equipment and procedures used are complex and sophisticated. This is because rock is not homogeneous and no single efficient device can be designed to bore through all types. The boring device (drill bit) must be changed frequently, and each time the drill pipe must be pulled out of the hole. Powerful equipment is required to hoist the drill pipe. For example, the weight of a drill string or casing string for a medium depth well (4,000 m) may exceed 500 tonnes. Powerful pumps are also required to circulate the fluid that flushes out the rock chips. Rocks have varying strength and stability characteristics that can cause problems and there are a number of other special conditions that may cause delays, or may result in the hole not being finished, if proper techniques and equipment are not used. The procedure for drilling a conventional well is described in the following paragraphs.

When drilling on land, the first step is the building of a road to the well site and preparation of the site for the drilling rig. In the Arctic, snow roads to the drilling site are built during winter and drilling platforms, as described in Section 4.3.1, are constructed to prevent melting of the permafrost. Site preparation involves levelling an area about 125 metres square, digging or building a pit that can hold 1 to 2

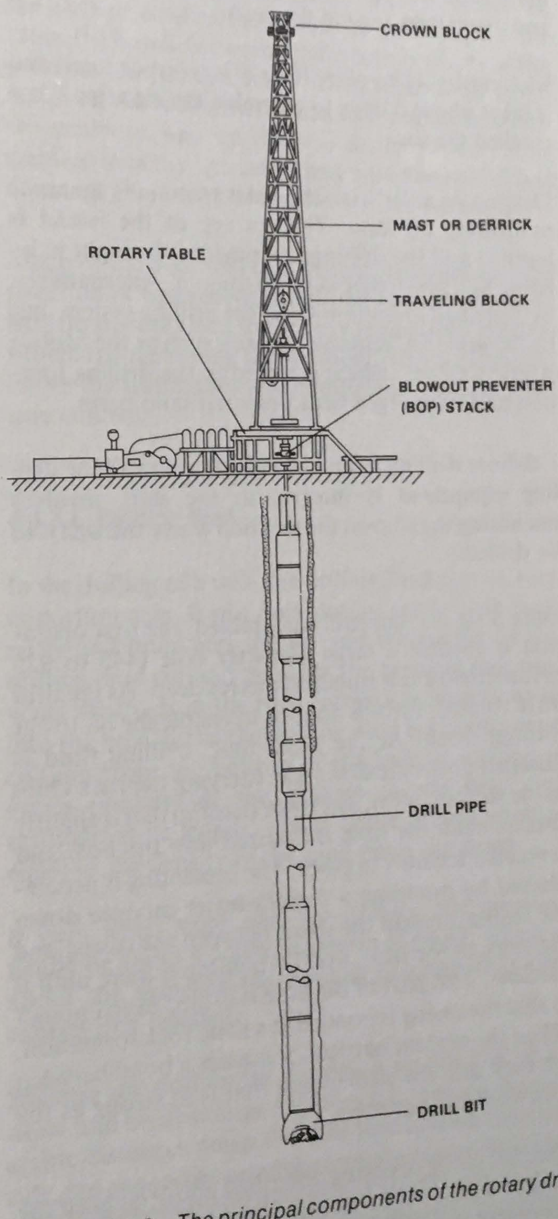

FIGURE 4.4-2 *The principal components of the rotary drilling system.*

thousand cubic metres of drilling wastes, and ensuring that there is a solid flat level area 15 to 20 metres square near the middle of the platform to support the parts of the drilling rig that lift the heavy loads. A small cellar about 1 metre square and 1 metre deep is dug and a section of large diameter pipe, 5 to 6 metres in length, is cemented into the ground at the spot where the well is to be drilled. The remainder of the space is used for the storage of pipe, drilling fluid mixing and processing, power generation equipment, sewage treatment equipment and living accommodation for the drilling personnel.

The drilling rig is then moved to the site in pieces that can be efficiently moved by truck (or sometimes by air) and that can be safely and conveniently handled by the drilling crew with the equipment available at the site. At the site the drilling equipment is installed and assembled around the cellar.

Moving the rig involves 10 to 20 large truck loads and it takes about 5 days to assemble the rig after it has reached the site.

Drilling on an artificial island is essentially the same as drilling on land. The surface of the island is levelled and the drilling equipment is brought in by barge and hoisted or skidded upon it. Alternatively, as described in Section 4.3.2, the drilling system may be integral to a 'reusable' caisson such as the Mobile Arctic Caisson, which is towed to the drilling location and submerged on a prepared sand berm.

Offshore drilling from a drillship, where all the drilling equipment is integral to the ship, involves anchoring the ship on the location where the well is to be drilled.

Once a rig is completely assembled, the first operation is to drill a large diameter hole (445 to 925 millimetres) a few hundred metres deep. As the drill bit is rotated, force is applied to enable the bit to cut through rock. At the same time, drilling fluid is pumped down the drill pipe, carrying the rock chips to the surface. Next, steel pipe (casing) that is slightly smaller than the hole is lowered into the hole and cemented securely in place. The cementing is accomplished by pumping a cement-water mixture down the casing, and up the space between the casing and the sides of the hole, and by holding it there until it hardens. This part of the hole is drilled deep enough so that the casing is bonded to a solid rock formation. When the cement hardens, it creates a bond between the rock and the steel casing that is as strong as the rock that was removed.

The first string of casing described above is called the surface casing. It forms an anchor for the blowout preventer, which is bolted to a flange on top of the surface casing. The blowout preventer consists of a series of valves designed to seal the top of the hole against pressure from the hole.

After the first casing is securely cemented in place and the blowout preventers are installed and tested, drilling continues until the planned depth or geological objective is reached.

The actual drilling operation involves rotating the bit and flushing out the rock cuttings until the hole is deepened by the length of a single joint of drill pipe (10 metres). The drill pipe and bit are then raised up, another joint of drill pipe is added and drilling continues. From time to time the bit becomes dull and must be changed. The complete string of drill pipe is then hoisted out of the hole, the bit replaced and the string run back to the bottom. Bit life varies in accordance with bit design and the nature of the rock being drilled, and may range from 20 to 100 hours.

As the hole is drilled deeper, additional casing is installed at pre-determined depths and cemented in place. With each installation of a casing string it is necessary to reduce the size of the bit and, of course, the subsequent string of casing. If the surface casing string were 76 centimetres in diameter, for example, and run to 100 metres, the next string of casing may be run to a depth of about 450 metres. This casing would be cemented in place in the same manner as the surface casing. Afterwards, a smaller bit, about 45 centimetres in diameter, would be run through the 50 centimetre casing and drilling resumed. The next string of casing would be about 34 centimetres in diameter and would be run to a depth of about 1,500 or 2,000 metres. The smallest practical casing diameter is 12 centimetres and is run into a hole drilled with a slightly larger bit.

Evaluation of the wellbore takes place during the drilling operation. Electrical and radioactive devices are run into the hole before each string of casing to measure the characteristics of the rock and the fluid in the rock. The samples of rock chips that are returned to the surface are examined for oil, composition and the presence of fossils.

From time to time a special bit is run which enables a long cylindrical section of rock, called a core, to be recovered. The core provides the geologist with much more information to evaluate rock properties such as porosity and permeability, oil saturation and electrical and radioactive characteristics. It also permits a detailed examination for fossils.

Technically, the drilling process is completed when the total depth of the well has been reached, electrical

logs have been run, and casing has been run and cemented. Further evaluation at this point, in the form of testing, is frequently carried out. This involves perforating holes in the steel casing and allowing the fluids in the formation to flow to the surface under controlled conditions. The zones for testing are selected from well logs and other information.

Plates 4.4-4, 4.4-5, 4.4-6 and Figure 4.4-3 show the main components of drilling systems and Figure 4.4-4 is a schematic showing the subsurface components of a well.

4.4.3 PRESSURE CONTROL

The spaces between the grains of sedimentary rocks are filled with fluid, usually salt water, but occasionally oil or gas, or a mixture of all three. This fluid exists under pressure. The pressure level is usually related to depth, a normal pressure being equivalent to the weight of a column of water from the surface to the depth of the zone. Thus, for example, if a layer of sandstone existed at a depth of 1,500 metres and it was saturated with water, under normal conditions the pressure would be about 14,500 kPa, or 9.5 kPa per metre of depth. Under some conditions the pressure may be higher than this; this is referred to as an overpressured zone. On the other hand, an underpressured zone may also be encountered.

PLATE 4.4-4 *The derrick mast, a principal component of the drilling system.*

When a borehole penetrates a subsurface formation, the fluids in the penetrated zones may enter the borehole if the pressure in the rock is greater than the hydrostatic pressure of the fluid in the borehole. In the early days when the wells were drilled with cable tools, the boreholes were usually totally empty so the pressure was almost zero. When these wells penetrated oil reservoirs, there was a tremendous flow into the wellbore, and up the well to the surface. This resulted in many "gushers" and unfortunately this is an image that many people have of oil wells today.

Much of the planning of a drilling program and the selection of equipment is directed towards ensuring that fluids contained in the rock formations are prevented from entering the wellbore. This section describes the techniques and equipment used for pressure control.

4.4.3.1 Drilling Mud

In the drilling of a well, the drilling fluid plays a very important role. It not only flushes the broken rock away and lubricates the bit, but the weight of the drilling mud column provides the pressure that prevents the fluids in the rock formation from flowing into the hole. Since the drilling mud is a continuous column from the bottom of the hole to surface, it exerts pressure at the bottom of the hole and throughout its length. The pressure at any point is equal to the density of the mud times the depth.

If pure water were used for drilling, the pressure would be about 9.5 kPa per metre of depth, which is about the same as the normal pressure that one expects in a reservoir.

Because the drilling fluid serves a number of functions, and because large volumes are pumped considerable distances down the drill pipe and up the outside, the properties must be carefully controlled. The critical properties of drilling fluid are density, viscosity, resistance to shear, and the tendency to cause the rock face to deteriorate.

PLATE 4.4-5 *The rotary table rotates the drill string, causing the bit on the bottom to chip off pieces of rock.*

Drilling mud is usually a complex mixture of water, thickening agents, corrosion inhibitors, lubricating components, thinners, freeze dispersants and clay inhibitors. Because of these additives the fluid is always heavier than water. Additional weight is created by adding an inert dense solid called barite (barium sulphate). When properly mixed with the other mud materials, it is possible to increase the density of drilling mud to twice that of water, and under special circumstances even higher. In addition to barite, chemical additives consist primarily of clay, potassium chloride, sodium bicarbonate, and small quantities of organic materials.

Under normal drilling operations the drilling engineer endeavours to maintain the pressure at the bottom of the hole exerted by the column of drilling mud 2,000 to 2,800 kPa higher than the pressure in the formation (the differential may be higher or lower than this depending on depth). If there are indications that the weight of the mud column is too low, drilling is immediately stopped and the density of the mud increased by adding more barite. Drilling is only resumed when a pressure overbalance is provided.

Thus, the weight of the drilling mud is the primary mechanism for maintaining well control. Blowout preventers are only used to control pressure when the weight of the mud column is not effective.

4.4.3.2 Pressure Prediction

As drilling continues deeper and deeper, early detection of a change in subsurface reservoir pressure is essential to maintaining pressure control with the drilling mud system. As the bit moves deeper, the formation pressure increases, but the pressure exerted by the mud column also increases, so that the differential is constantly maintained.

The Mackenzie River Delta, particularly offshore, is an area where abnormally high pressures are encountered so that the density of the mud must be frequently adjusted. Fortunately pressure changes do

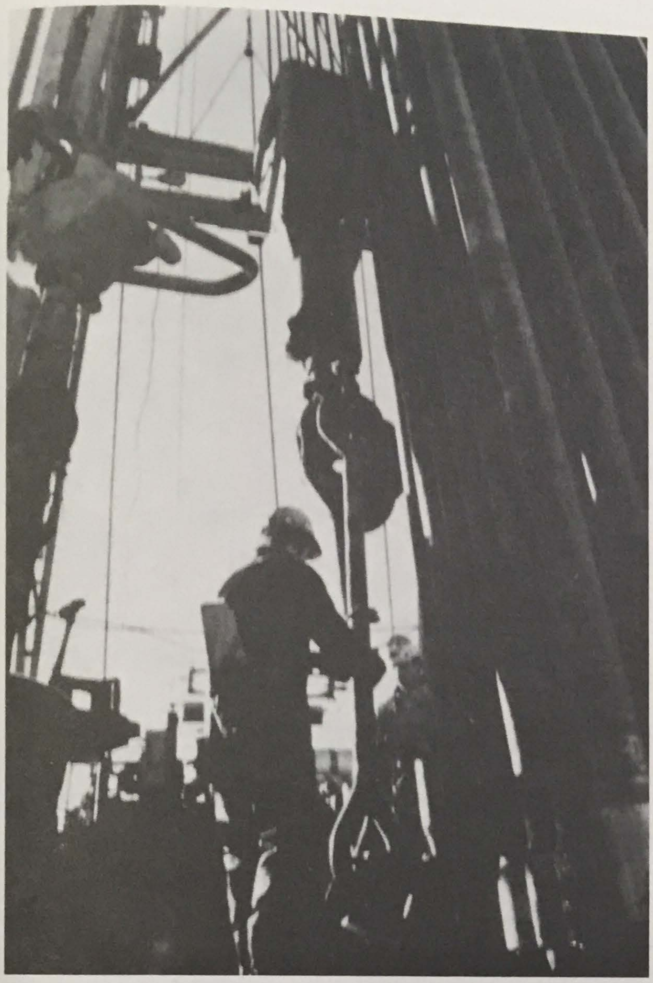

PLATE 4.4-6 *The drill pipe extends from the bit at the bottom of the hole to the surface and is rotated at the surface. Each time the bit must be replaced, the entire drill pipe string must be removed from the hole.*

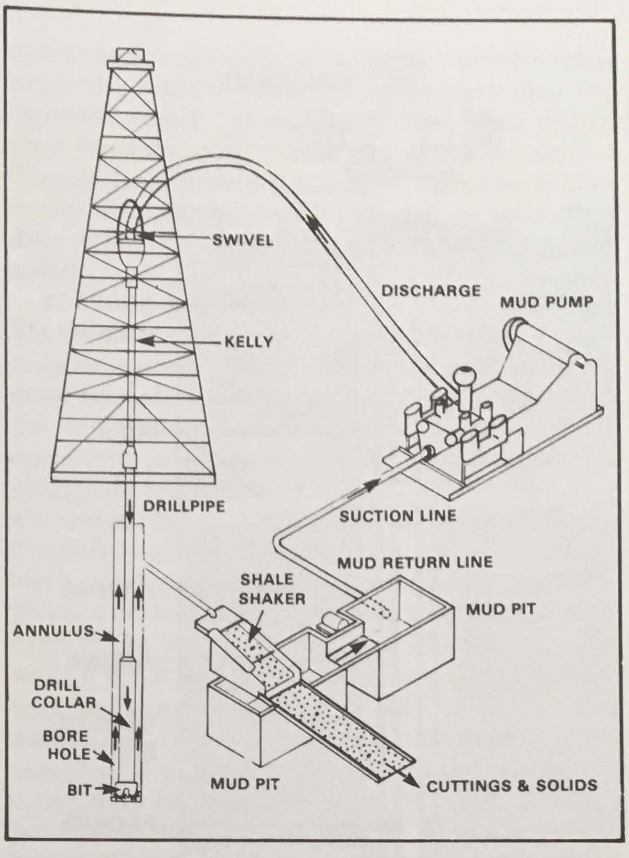

FIGURE 4.4-3 *The mud system is an important part of a drilling system. Drilling mud consists of water, a thickening agent such as bentonite and a high density material such as barite, to control the weight of the mud. The mud is pumped down the inside of the drill string and out the bit. It lubricates the bit, and carries the cuttings back to the surface, while at the same time exerting sufficient pressure inside the hole to control formation pressures.*

not occur instantly. There is usually a transition zone, from 15 to 90 metres thick, where the pressure gradient changes from one level to another. A number of sensitive devices operated by drilling crews facilitate quick detection of the pressure gradient change, thereby prompting corrective action.

One of the most obvious signs of a pressure imbalance is an increase in the amount of drilling fluid in the surface tanks. Sensitive devices measure the total volume of fluid in the drilling system and also measure the level of the mud in the surface tanks. Since the mud is circulated down the drill pipe, up the casing, into the mud tanks and then pumped down the drill pipe again on a continuous circulation basis, there should be no increases or decreases in total system volume unless something unusual is occurring. An increase in fluid volume at the surface means fluid must be entering the wellbore from the drilled formations. The additional fluid may be gas, oil or water, but gas is the frequent cause. As the gas rises with the mud column and the pressure is reduced, it expands, causing more volume gain at the surface. Gas within the mud system greatly reduces the pressure of the mud column at the bit, further aggravating an underbalanced pressure situation.

As soon as the change in fluid volume is detected by the drilling crew, drilling is stopped and the blowout preventer is closed against the drill pipe to ensure that no more fluid enters the wellbore. At this point the drilling crew will be able to measure the pressure at the surface beneath the closed blowout preventer. This permits calculation of the required drilling mud density, and drilling will be resumed when the desired density is achieved.

The drilling crews are carefully trained for controlling pressures, both in the classroom and on the drilling rig. Regular drills are held so that they can respond quickly to changes in well conditions. Careful records are kept to record the time it takes the crew to determine a change in fluid volume, to close the blowout preventer, and to take corrective action.

There are other techniques that enable the drilling crew to determine the change in pressure before a volume change occurs at the surface. Sensitive detec-

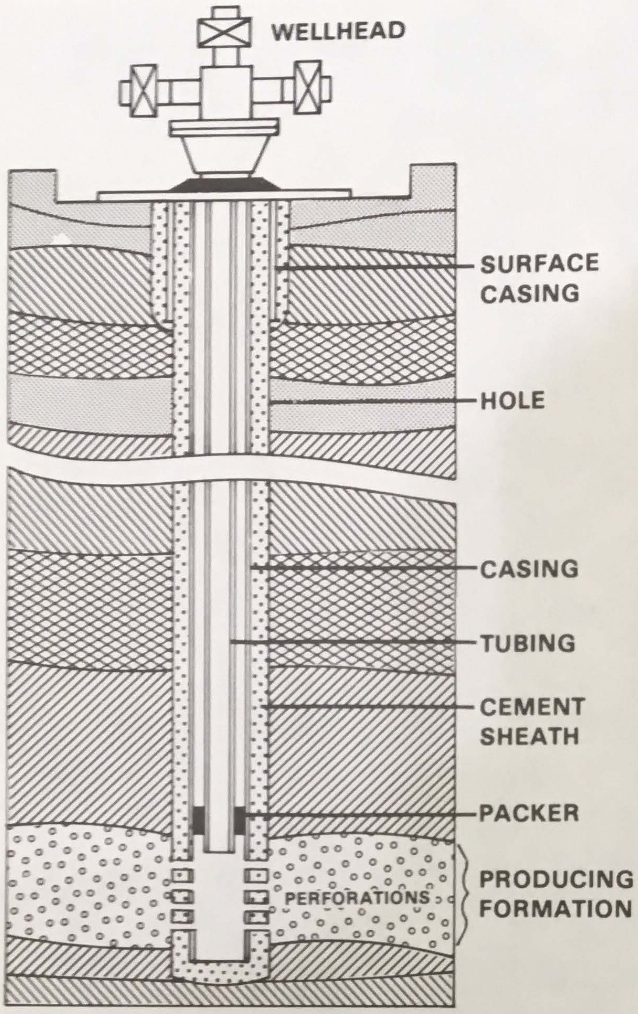

FIGURE 4.4-4 *After a hole is drilled, it is cased with steel casing and the casing is cemented to the walls of the hole. Several strings of casing, each successively smaller than the previous string, are used to support the walls of the hole and contain formation pressure. In a producing well, the oil production flows through perforations in the casing and up a small diameter pipe (called tubing) to the surface.*

tors enable the mud loggers (people who continually measure the characteristics of the drilling mud) to determine minute changes in gas content in the mud. An increase in gas concentration is usually the first indicator of a changing pressure regime. The shape and density of the rock chips give indications of abnormal pressue changes in the rock formations, as does a rapid change in the rate at which the hole is being drilled.

In Beaufort Sea-Mackenzie Delta wells, essentially every device available to the industry is provided for detecting pressure, measuring changes in well conditions, and responding to those changes.

As more drilling is carried out in the Region, it becomes easier to predict pressures. In the first wells drilled in an area, pressures can be estimated from seismic information. After the first well has been completed, the pressure can be physically measured. When development wells are drilled, pressure prediction is very accurate using available data obtained during exploration drilling.

4.4.3.3 Blowout Preventers

The blowout preventers used in the Beaufort Sea-Mackenzie Delta Region have a very high pressure rating, with built-in redundancy to provide protection in the event of failure of a subcomponent of the preventer. Blowout preventers, as shown in Plates 4.4-7 and 4.4-8, have three valves or rams which close against the drill pipe. Only one is required for pressure control. The fourth ram is the blind ram or shear ram, and can actually cut off the pipe, if necessary, to form a seal. Additional valves on the side of the blowout preventer enable fluids to be bled from the well or pumped into the well at a controlled pressure and rate. All of these devices and valves are controlled by the driller from his work station.

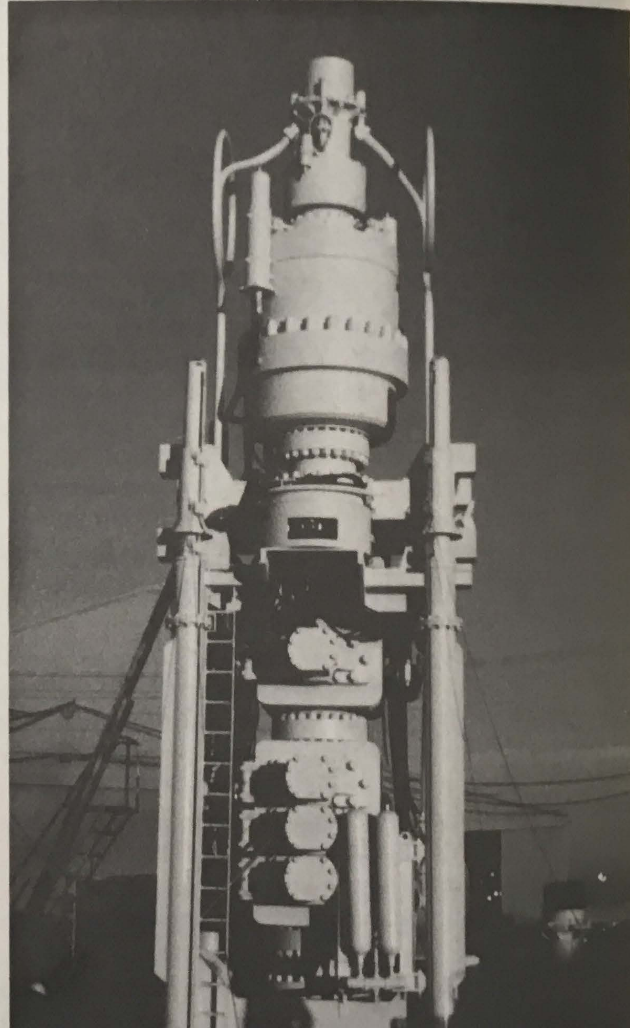

PLATE 4.4-7 *The blowout preventer is the series of valves placed on the wellhead. The blowout preventer is closed automatically or from remote stations in the event that the mud weight is not controlling formation pressure. The subsea blowout preventer, illustrated in this photograph, is placed on the wellhead on the sea floor. It weighs about 150 tonnes.*

PLATE 4.4-8 *The land type blowout preventer is similar to the subsea blowout preventer.*

Blowout preventers are tested regularly to a pressure that ensures that the system is capable of withstanding any pressure that may be encountered during the drilling of a well.

The valves in the blowout preventer are all fail-safe. This means that the valves are held in the open position by hydraulic pressure. If there were a failure in the hydraulic system, which might happen because of some surface disaster, the blowout preventer will automatically close.

In offshore areas where ridge keels from ice floes may scour the sea floor, the blowout preventers on floating drilling systems are placed below the sea floor in "glory holes." These glory holes are dredged prior to drilling to enable placement of the blowout preventer at a depth where it will be unaffected by ice scouring.

4.4.4 EXPLORATION WELLS VERSUS PRODUCTION WELLS

An exploration well is a well that is drilled to secure geological information. A production well is drilled for the purpose of producing oil or gas. Some exploration wells are referred to as "wildcats," which implies a high risk venture - not an inappropriate term in the expensive search for oil. Technically, some people class an exploratory well as one which is a certain distance from proven production, about three kilometres. In exploration wells there are few subsurface data to help the drilling engineers predict what lies ahead.

The technique for drilling a production well is basically the same as for an exploration well, although more evaluation work will usually be carried out on the exploration well. For conventional onshore operations in southern Canada, if an exploration well results in a discovery, the well will be retained as a future producer. After drilling and evaluation, the discovery well would be safely suspended by putting mechanical and cement plugs in the casing above the production formation, and also securing the wellhead at the surface. In the case of offshore wells, while it is not impossible to preserve an exploration well for future production, it may be complicated and difficult. The main problem is that these wells are usually drilled from a mobile drilling unit, so the well could only be completed as a producer if it was practical to place the wellhead on the sea floor, and later tie the well into permanent production facilities. In most cases, offshore exploratory wells are permanently abandoned even if they are discoveries.

Production wells are drilled more quickly than exploration wells because of the knowledge gained during exploration and because there is less time spent in evaluation. The activity of well completion adds some time to the process. Well completions are discussed in more detail in Section 4.5.1.

During production well drilling, there will be a concentration of activity, since a large number of holes will be drilled from a single location, and two or more drilling rigs may be operating beside each other. Wells will be drilled in groups of five to fifteen, depending on the depth of the productive formation, the size of the field and, in the case of onshore fields, the availability of suitable sites. Onshore, the wellheads will be spaced up to thirty metres apart in a straight line or in parallel lines. On islands, they will be approximately three metres apart in a square pattern. All but one of the wells in each group will be directionally drilled to penetrate the producing formation some distance away from the surface location.

At some locations, two or perhaps three drilling rigs will be operating side by side, and new wells will be drilled a few metres from wells that are already producing. There are potential hazards created by this situation, because an accident at one drilling rig could endanger the other drilling activities or damage the control valves on nearby producing wells. Carrying out multiple operations in a confined space is com-

mon practice on most offshore drilling and produc-tion platforms, and protective arrangements and special operating procedures are used to reduce the risk and consequences of an accident. Onshore sites and offshore islands both provide greater space and more opportunity to take defensive measures than does a traditional offshore platform. Fire walls and protective cages are placed around wellhead equipment, certain operations are shut down when other operations are taking place, and strategically placed fire fighting equipment is installed to automatically detect and respond to fires. In addition, down hole shut-in devices, combined with an automatic surface control system, are installed to shut off all production immediately in the event of a hazardous situation arising. Because of these measures the effect of drilling operations on the safety of other operations will be negligible.

4.4.5 DIRECTIONAL DRILLING

In conventional southern oil fields on land, where surface access is not a problem, producing wells are drilled vertically. Where, for example, a 65 hectare spacing pattern is used, wells are drilled in a grid, each well 800 metres from adjacent wells. A series of lease roads provide access to each well site. Each well site consists of one or two hectares of land so that space is available in the event that a rig must be moved back to the well for down hole servicing.

Offshore, and on the tundra, it is not practical to establish multiple surface locations. In these areas one surface location is used as a base from which a number of producers - perhaps as many as 50 - could be drilled.

Directional drilling is another part of the oil industry that has become a specialized science. It is now possible to hit a subsurface target 30 metres in diameter, 3,000 metres below the surface, three to five kilometres from the surface location. The industry record for step out distance was achieved in Cook Inlet in the 1960's. The distance was almost 5 kilometres away from the surface location at a vertical depth of almost 3,000 metres.

The drilling of a directional well is mechanically identical to drilling a vertical well. The well is drilled vertically at least to the depth where surface casing is run. At a predetermined depth, a specialized tool is run into the hole to deflect the bit. The depth where the first deviation is desired is called the "kick-off" point. A specialized drilling assembly is used which includes a hydraulic motor suspended on the bottom of the drill pipe. The bit is rotated by the hydraulic motor so that the pipe does not have to be rotated. A "bent sub," which is a section of pipe with a 2 or 3 degree deflection, is run above the hydraulic motor. The bit is oriented using direction-indicating devices ... accomplished by pumping mud down the drill pipe through the hydraulic motor. This process is continued with the angle being increased by about 2 to 3 degrees for each 30 metres drilled, establishing a smooth curve. Ultimately an angle as high as 60 degrees can be established and even higher in extraordinary situations. Once the desired angle has been established, conventional drilling is resumed and the hole again becomes straight, but the angle of deviation is maintained. The long, smooth curve in the wellbore does not affect the ability to rotate or move up and down the relatively limber drill string.

Figure 4.4-5 is a cross-section view of a directionally drilled well. It illustrates the kick-off point and the 2 degree angle which builds to an ultimate deviation of 45 degrees. Frequent well surveys enable the precise location of the well to be determined at regular intervals, and corrective action can be taken if deviation is not according to plan. In the development of an oil field, a directional plan is prepared for every producing well to minimize the chances of well interference. The target, or location where the well will penetrate the producing horizon, will usually be spaced on a uniformed grid. Thus, one could end up with a 65 hectare spacing with the bottom of each well 800 metres from each adjacent well, as in the conventional example.

Directional drilling is also used for relief wells. It is important to have an accurate description of every wellbore so that if a relief well were required, the engineers could establish a target. The relief well would be drilled to intersect the wellbore of the blowout at some predetermined depth where a 'kill' could be affected.

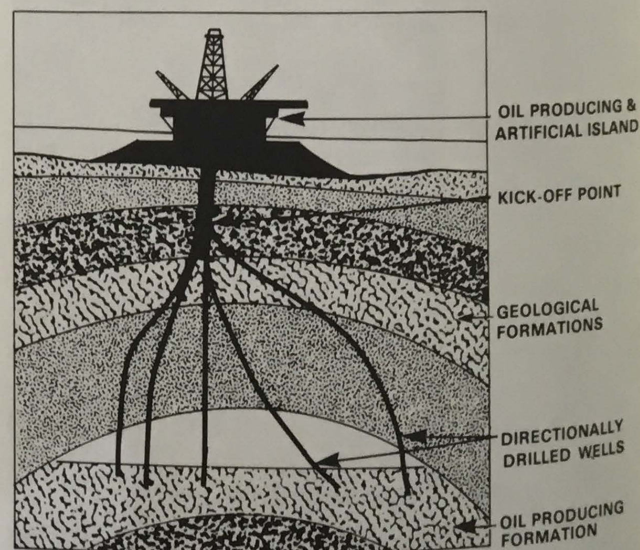

FIGURE 4.4-5 *The producing wells drilled from an offshore location are drilled on an angle so that adequate coverage of the reservoir can be achieved. Angles of 45 degrees are common while angles up to 70 degrees are not unusual. A rule of thumb is that the horizontal reach is approximately equal to the vertical depth.*

mon practice on most offshore drilling and production platforms, and protective arrangements and special operating procedures are used to reduce the risk and consequences of an accident. Onshore sites and offshore islands both provide greater space and more opportunity to take defensive measures than does a traditional offshore platform. Fire walls and protective cages are placed around wellhead equipment, certain operations are shut down when other operations are taking place, and strategically placed fire fighting equipment is installed to automatically detect and respond to fires. In addition, down hole shut-in devices, combined with an automatic surface control system, are installed to shut off all production immediately in the event of a hazardous situation arising. Because of these measures the effect of drilling operations on the safety of other operations will be negligible.

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Offshore, and on the tundra, it is not practical to establish multiple surface locations. In these areas one surface location is used as a base from which a number of producers - perhaps as many as 50 - could be drilled.

Directional drilling is another part of the oil industry that has become a specialized science. It is now possible to hit a subsurface target 30 metres in diameter, 3,000 metres below the surface, three to five kilometres from the surface location. The industry record for step out distance was achieved in Cook Inlet in the 1960's. The distance was almost 5 kilometres away from the surface location at a vertical depth of almost 3,000 metres.

The drilling of a directional well is mechanically identical to drilling a vertical well. The well is drilled vertically at least to the depth where surface casing is run. At a predetermined depth, a specialized tool is run into the hole to deflect the bit. The depth where the first deviation is desired is called the "kick-off" point. A specialized drilling assembly is used which includes a hydraulic motor suspended on the bottom of the drill pipe. The bit is rotated by the hydraulic motor so that the pipe does not have to be rotated. A "bent sub," which is a section of pipe with a 2 or 3 degree deflection, is run above the hydraulic motor. The bit is oriented using direction-indicating devices and rotation of the bit is established by pumping mud down the drill pipe through the hydraulic motor. This process is continued with the angle being increased by about 2 to 3 degrees for each 30 metres drilled, establishing a smooth curve. Ultimately an angle as high as 60 degrees can be established and even higher in extraordinary situations. Once the desired angle has been established, conventional drilling is resumed and the hole again becomes straight, but the angle of deviation is maintained. The long, smooth curve in the wellbore does not affect the ability to rotate or move up and down the relatively limber drill string.

Figure 4.4-5 is a cross-section view of a directionally drilled well. It illustrates the kick-off point and the 2 degree angle which builds to an ultimate deviation of 45 degrees. Frequent well surveys enable the precise location of the well to be determined at regular intervals, and corrective action can be taken if deviation is not according to plan. In the development of an oil field, a directional plan is prepared for every producing well to minimize the chances of well interference. The target, or location where the well will penetrate the producing horizon, will usually be spaced on a uniformed grid. Thus, one could end up with a 65 hectare spacing with the bottom of each well 800 metres from each adjacent well, as in the conventional example.

Directional drilling is also used for relief wells. It is important to have an accurate description of every wellbore so that if a relief well were required, the engineers could establish a target. The relief well would be drilled to intersect the wellbore of the blowout at some predetermined depth where a 'kill' could be affected.

FIGURE 4.4-5 *The producing wells drilled from an offshore location are drilled on an angle so that adequate coverage of the reservoir can be achieved. Angles of 45 degrees are common while angles up to 70 degrees are not unusual. A rule of thumb is that the horizontal reach is approximately equal to the vertical depth.*

To minimize friction during directional drilling and also to reduce the effect that the drilling fluid has on the producing formation, it may be necessary to use an oil based drilling fluid. Oil based fluid is handled in a closed system that prevents its escape to the surrounding environment. In the event that the fluid becomes contaminated, it is taken to a central facility where it is processed to remove the contaminants and then reused. This drilling fluid and the methods for handling it are widely used on offshore platforms in the North Sea and in the Gulf of Mexico. With this system, all the rock chips will be coated with oil, but they will be either washed or incinerated to remove the oil before disposal.

4.4.6 DRILLING PROBLEMS

During the course of drilling a well there are a wide variety of things that can happen to delay progress and, in extreme cases, to cause the well to be abandoned and a new well drilled. Exploratory wells, particularly the first ones drilled in a new area, are the most problem prone because of the many unknown factors. In any region there are conditions that are more or less unique. These require special equipment, designs and procedures. This subsection describes some of the problems that are taken into consideration in the design and drilling of wells in the Beaufort Sea-Mackenzie Delta Region.

4.4.6.1 Permafrost

Permafrost is a condition where the rock formation and soil is permanently frozen. It exists almost everywhere on land in the Arctic and in various locations offshore. The offshore permafrost is somewhat different from the land permafrost in that it is in a deteriorating state. The offshore permafrost was formed thousands of years ago when the areas now submerged were actually above sea level. The permafrost offshore is now melting, both from the top and the bottom, so that when it is encountered it is usually 30 to 100 metres below the sea floor and may extend to a depth of up to 600 metres. The nature and severity of the effect that it has on drilling depends on the kind of rock formation and the depth at which it is encountered.

In onshore areas, where the drilling site is underlain by ice-rich soils, removal of the insulating layer of vegetation and heat from the drilling activity can cause the permafrost to melt. The resulting water-soil mixture may be too weak to support drilling. Thawing can be prevented by placing an insulating layer of gravel under the equipment and by cooling the drilling fluid. In addition, an extra string of casing may be installed to create a 'thermos' effect, or insulation may be applied to the casing to restrict heat loss.

Permafrost encountered deeper in the hole has a number of effects. Warm drilling mud circulating in the wellbore can melt the permafrost. If the soil or rock has a very high moisture content, so that the particles of the rock are not in contact with one another, melting may cause the rock to disintegrate. The thawing effect in the wellbore in Beaufort Sea-Mackenzie Delta wells is minimized by keeping the temperature of the drilling fluid close to the freezing point and by drilling through the permafrost section very quickly. In land wells it is common to run an extra string of casing equipped with mechanical insulation to prevent heat from the drilling fluid from melting the surrounding permafrost.

The presence of permafrost requires special cements that set under low temperature conditions to be used for cementing the upper strings of the casing in the well. Special care must be taken to ensure that the casing remains intact even if permafrost melting does occur. This has been a problem in some of the offshore wells drilled in the Region and has caused changes in design.

In producing wells, permafrost will not present any particular incremental problem during the drilling operation, but the potential thawing of permafrost over the long term production of warm fluids from the reservoir is of concern and must be taken into consideration in the design. In locations like Prudhoe Bay, designs have been developed and tested successfully over the past several years. Figure 4.4-6 is a cross-section of a casing string design on a typical Prudhoe Bay well. This type of system may also be adopted in the Beaufort Sea-Mackenzie Delta Region.

4.4.6.2 Shallow High Pressure Water Zones

Permafrost provides an impermeable layer over all of the rocks beneath it. Under normal sedimentary conditions, the fluids that are contained within the newly deposited sediments are gradually squeezed out as compaction occurs. Water squeezed out of the rock usually finds its way to the surface. In localized areas in the Beaufort Sea-Mackenzie Delta Region, the permafrost has prevented the normal migration of fluid so that unusually high pressures may be encountered immediately below the permafrost zone. If this zone happens to be sand, an artesian situation exists. When the drill bit penetrates the permafrost layer it drills into the sand and there is a tendency for the water to flow to the surface. Shallow water flows have been a problem in some of the offshore Beaufort Sea wells.

The occurrence of shallow high pressure zones is very difficult to predict, however, seismic surveys may indicate the possible presence of these zones. Weak rock formations near the surface and the presence of

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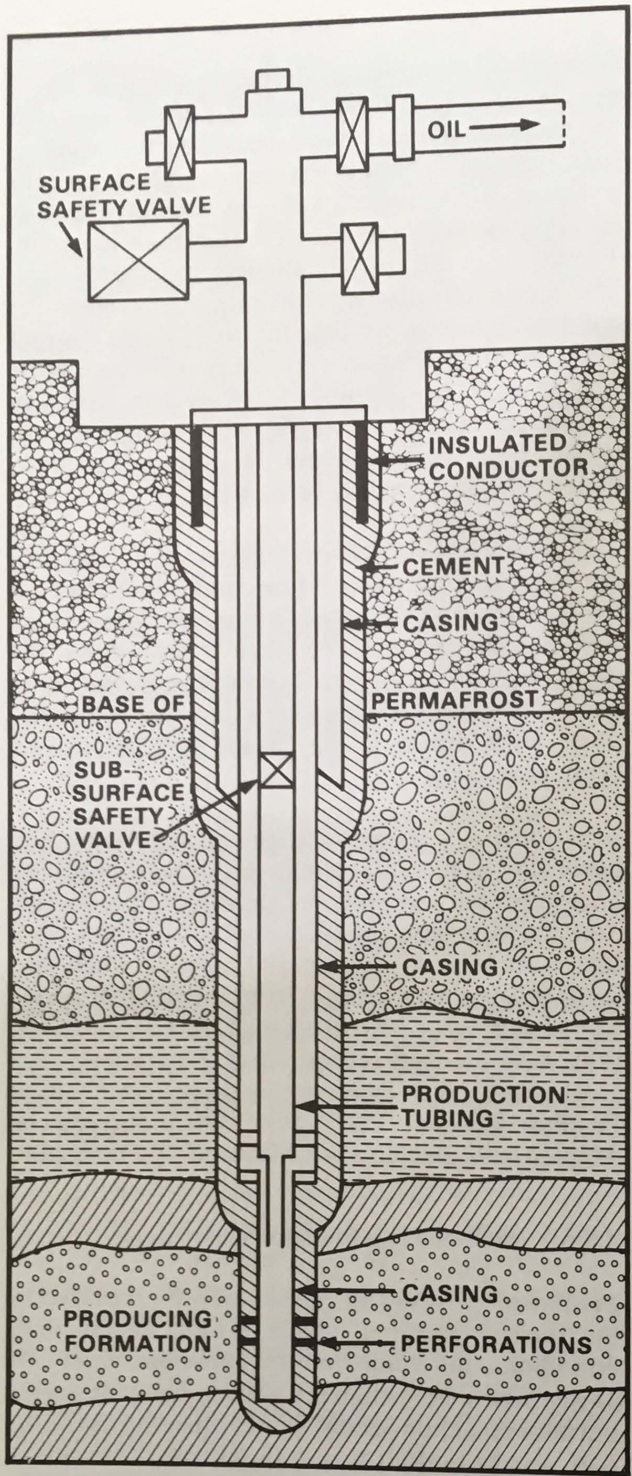

FIGURE 4.4-6 *Arctic wells require special precautions because of the presence of permafrost.*

permafrost above the zones, usually prevent the use of weighted drilling mud to control the flow of water. It may be necessary to permit the water flow to continue until the pressure is depleted, or until the water freezes.

It may be desirable in the future, particularly in areas where field development will occur, to investigate the practicality of depleting these water zones. This would greatly decrease the problems and risks associated with these zones. An attempt to contain the shallow water zone, if unsuccessful, could result in casing failures after a well has been drilled to greater depths.

Figure 4.4-7 illustrates the occurrence of a shallow water high pressure zone beneath the permafrost.

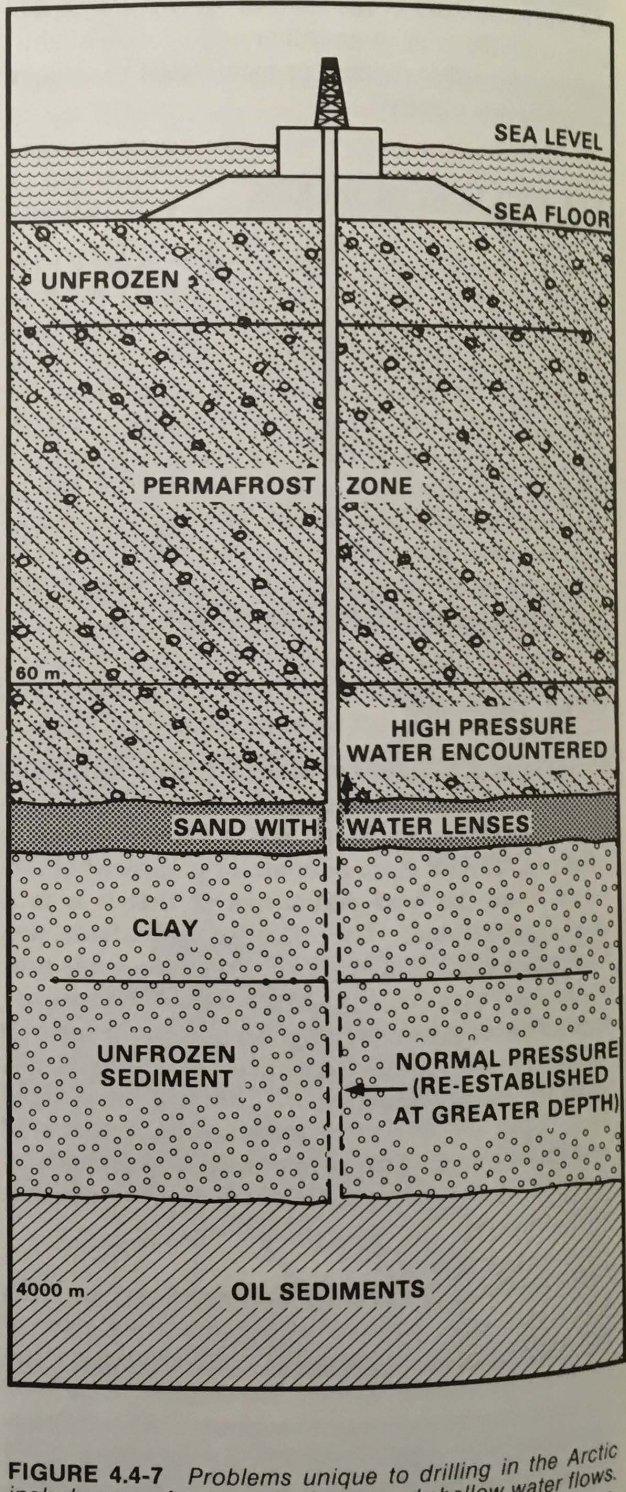

FIGURE 4.4-7 *Problems unique to drilling in the Arctic include permafrost, gas hydrates, and shallow water flows. Proper drilling procedures have made it possible to overcome these problems.*

4.4.6.3 Gas Hydrates

Gas hydrate is a frozen mixture of water and natural gas which can be encountered at depths to 1,500 metres. It can exist as a solid at temperatures above 0°C, due to a unique combination of gas and water composition, pressure and temperature. It decomposes, or melts, when heat is added or the pressure is reduced, thereby releasing the natural gas. Gas hydrates are not uncommon in conventional operations in western Canada where gas is exposed to cold conditions in pipelines or surface equipment. It is unusual for gas hydrates to occur beneath the surface in western Canada but it has been a common phenomenon in permafrost zones.

The melting of gas hydrates while drilling a well may cause a problem because the evolved gas occupies space in the mud column, thereby reducing the density and the pressure that the mud exerts at the bottom of the hole.

Proper drilling procedures and good well design defuse the problems associated with hydrates. Hydrate sections are drilled slowly to minimize the quantity of hydrate material in the mud system. This allows the hydrates to melt and to be separated without a serious effect on the mud density. It has now become common practice to refrigerate the drilling mud to a temperature below that at which hydrate decomposition will occur. Extra strong casing is run through the hydrate zone, to withstand the collapse pressures that may develop if decomposition of hydrates occurs outside of the wellbore.

4.4.6.4 Abnormal Pressures

Abnormal pressures were introduced in Section 4.4.3. There are several reasons why pressures may be higher than normal. One explanation was given in the discussion on permafrost, where the impermeable layer prevents the normal migration of fluids from the deposited sediments as they are compacted, thus resulting in high hydraulic pressures. It is also possible for porous and permeable formations to be pressure connected with higher pressure zones deeper in the wellbore. Fortunately, abnormal pressures can be predicted in advance, and the weight of the mud column adjusted before the full impact is felt in the wellbore. The standard overbalance that is always carried while drilling also accommodates some increase in pressure, and the blowout preventer assures that any pressure could be contained in an emergency.

Careful selection of the casing setting depths is important in controlling abnormal pressures. Normally one tries to set the casing string into the transition zone of the abnormally high pressured zone so that other sections of the well are not exposed to the higher weight mud column that must be carried through the high pressured zone.

Occasionally pressures may be abnormally low. This is common in older oil field areas where pressures have been depleted by production. If abnormally low pressures are encountered, the mud column may be too heavy and it can flow into the low pressure rock, resulting in lost circulation. Lost circulation is regained by adding to the mud materials, which will reduce the porosity in the 'thief' zone. Occasionally it is also necessary to lower the mud weight, but this must be done with caution, because the need to control higher pressure zones open to the wellbore.

In the Beaufort Sea-Mackenzie Delta Region, abnormal pressures are very common. The ability to detect these zones before they are drilled has improved substantially during the last five years. They show up on seismic records, on gas detectors in the drilling mud, in the density of the cuttings from the wellbore, as increases in penetration rate and in the shape of the drilled cuttings.

Procedures have been developed to predict and deal with these conditions. A technique known as 'kick tolerance' has been refined for the Region and is a particularly useful tool in choosing casing setting depths and determining the best drilling fluid density. This technique provides a measurement of the ability of the overall system to control well pressures. In particular, it indicates how much the density of the drilling fluid can be increased without risking the loss of drilling fluid into a normally pressured formation. In essence it provides for a carefully preplanned, graduated response to any pressure change. Other conventional pressure control techniques and procedures, along with suitably designed blowout preventers, provide the necessary control.

4.4.6.5 Blowout

The most catastrophic event that can occur while drilling is a blowout or a complete loss of pressure control. When this happens the mud column is insufficient to offset the pressure in a formation and the fluids flow into the wellbore in an uncontrolled manner. Fortunately they do not always flow to the surface. They may flow up the well and into a zone of lower pressure. This is known as an 'underground blowout' and, while it is still highly undesirable, it is not catastrophic in that uncontrolled flow does not occur at the surface.

Fluids in a blowout may escape to the surface in two ways; one is a flow up the casing and through the blowout preventers. This could only happen if there was a malfunction with all of the pressure control systems. The second is an uncontrolled flow of fluids

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on the outside of the casing. This could result from improper casing design, improper casing installation or a casing failure.

Blowouts are controlled by remedial measures at the surface or by drilling relief wells. Relief well drilling is described in Section 4.4.7. The probability of uncontrolled flow of oil at the surface from the deep zones in the Beaufort Sea-Mackenzie Delta is remote. This is because well control procedures improve with depth, as more strings of casing are run into the well and the mud column becomes longer, providing more time for corrective action. Worldwide statistics show that 88% of blowouts are gas rather than oil. This is also understandable since the entry of gas into the wellbore, and the subsequent expansion as the gas rises to the surface, aggravates the pressure loss situation.

4.4.6.6 Other Problems

Other drilling problems include loss of pipe or material down the wellbore, stuck pipe, caving in of the hole, swelling shale, and high bottom hole temperature.

Procedures for handling each of these problems in a safe and efficient manner have developed over many years of experience all over the world. Occasionally the problems necessitate abandonment of a well and the starting of a new well.

4.4.7 RELIEF WELL DRILLING

In the event that a well blows out and subsequent attempts to regain control at the surface in the original wellbore are unsuccessful, a relief well is a certain way of cutting off the flow in the uncontrolled wellbore. A relief well is drilled to intersect the wild well at some point deep below the surface, so that a high density fluid along with cement can be injected into the problem well. It is not necessary that the intersection be made at the bottom of the original hole. It is only necessary that it be made deep enough that the formations can withstand the pressures necessary to effectively bring the well under control.

In drilling the relief well, normal drilling equipment and directional drilling procedures are used. With the number of drilling systems that will be operating in the Region, there will be a variety from which a selection can be made. The type of equipment selected, and how it will be set up, will depend on the location of the well that is blowing out and the time of year.

The surface location of the relief well should be as close to the blowing well as safety premits, however, it must be separated sufficiently to eliminate inadvertent communication between the two well bores. The location of the relief well could be as close as 150 metres or as far as 2,000 metres from the blowing well. As previously mentioned it is important to know the precise location of every point in every well that is drilled in the Beaufort Sea-Mackenzie Delta Region, whether an exploratory well or a producing well, so that the intersection by a relief well can be properly planned, should an emergency ever develop.

If the wild well is located onshore, a new site will be prepared for the relief well as close as possible to the original well, if one is not already available. The most effective drilling system will be moved to the site, over snow roads in winter or by helicopter in the summer.

For offshore wells, a number of options will be available depending on ice conditions, depth of water around the location of the blowing well, the time of year and the nature of the blowout. If drilling is being carried out from an artificial island in the winter, a relief well may be drilled with a drilling rig placed on a thickened ice pad in the rubble field surrounding the island. A stabilized rubble field is established by early January and after that operations to thicken the ice could begin. This pad could be usable until June. Techniques for building thick ice pads have been tested and proved feasible, and exploratory drilling has been conducted on both grounded and floating ice pads. The drilling rig would be moved by icebreaking supply boats and helicopters. Alternately, a drillship could be moved into the rubble field, allowed to freeze there, and the drilling carried out from the stationary ship.

In the event the blowout occurred in the open water season, a drillship would be moved as close as possible to the island if the water is deep enough. Alternatively, the island would be enlarged to provide a base for the relief drilling rig. About 45 to 60 days would be required to drill a relief well and effect a kill for most wells in the Region. The advent of extended season floating drilling systems such as the conical drilling unit will provide a further option for the drilling of relief wells.

4.4.8 ACCOMMODATION AND UTILITIES

Approximately 100 personnel are required to drill a typical well in the Beaufort Sea-Mackenzie Delta Region. Self contained living accommodation for these people will be provided adjacent to drilling systems operating on islands or onshore. For floating drilling systems, personnel are accommodated onboard the ship.

Electricity and heat are supplied to the accommodation facilities from the drilling system utility supply.

Water will be obtained from the sea or nearby watercourses and treated to provide potable water for the accommodation facilities.

Each drilling system will be equipped with a packaged sewage treatment system capable of treating anticipated peak daily wastewater flows from the accommodation facilities. Solid waste generated from the living and dining components will be incinerated with combustible solid waste, such as packaging material, generated from drilling activities. Noncombustible solid waste and incinerator ash will be periodically transported to approved landfill sites.

4.4.9 POTENTIAL ENVIRONMENTAL DISTURBANCES

The drilling system creates by-products or waste materials which are subject to treatment and disposal. A summary of the sources, quantities and characteristics of drilling by-products is provided in this section. The environmental impacts of drilling are examined in detail in Volume 4.

4.4.9.1 Waste Drilling Fluid

About 90% of the constituent weight of additives in water based drilling muds is made up of barite, bentonite, lignite and lignosulphonate; all naturally occurring materials. There are a number of special fluids for specialized applications but generally fewer than a dozen products are required to control drilling fluid properties. All chemicals used in the drilling of wells in the Beaufort Sea-Mackenzie Delta Region are screened and approved for use by the Federal Government. Information on the quantities of all mud components are reported to the drilling authorities.

Quantities of drilling fluid are wasted from the system on a daily basis due to volumetric excesses caused by the addition of chemicals and water. The total amount of drilling fluid that will be discharged during the course of drilling a well will vary depending on the nature of the rocks being drilled, the complexity and cost of the fluid and time. In the case of a conventional lignosulphonate drilling fluid, approximately 1,500 cubic metres will be discharged in the course of drilling a 4,000 metre well. Where oil based fluids are used, essentially no drilling fluids are discharged.

4.4.9.2 Drill Cuttings

Rock chips or drill cuttings are flushed up from the drill bit with the circulating drilling fluid. The cuttings are removed from the fluid by screening and settling. Drill cuttings from onshore operations are generally allowed to build up along the side of the sump and when drilling is completed, are used to fill in the sump. Drill cuttings from offshore platforms are generally pumped overboard.

Drill cuttings generated when oil based drilling fluids are being used or when a formation containing oil is being penetrated, will be coated with oil. These cuttings are cleaned or incinerated before disposal.

During the drilling of a 4,000 metre well, about 200 to 400 cubic metres of drill cuttings will be generated.

4.4.9.3 Wash Water

During the course of drilling, the equipment and, particularly, the working area on the drill floor must be washed regularly to allow the drill crew to work safely. Usually small amounts of detergents are used to aid in the cleaning, and the end result is a mixture of fresh water with small amounts of drilling fluid additives, minute quantities of oil and grease and detergent. The amount of wash water that is used varies greatly depending on the operations that are being carried out, but is normally about 10 cubic metres per day.

4.4.9.4 Sewage Effluent

Accommodation facilities located adjacent to the drilling platform will generate wastewater from food preparation, laundry, toilets and showers. The wastewater will be subject to treatment in packaged (self-contained) sewage treatment plants with effluent discharge to the sea or to nearby watercourses.

It is estimated that approximately 20 cubic metres per day of treated effluent will be discharged from each platform.

4.4.9.5 Solid Waste

Solid waste materials generated by the drilling crews as well as packaging materials for drilling supplies will amount to approximately 350 kilograms per day. Combustible solid waste will be incinerated and the residue as well as noncombustible solid waste, amounting to about 14% of the total, will be landfilled.

4.4.9.6 Atmospheric Emissions

The operation of internal combustion engines on site to power the drilling and ancillary equipment will emit hydrocarbons, particulates, water vapour and nitrous oxides to the atmosphere. It is estimated that 145 tonnes per well will be emitted or, assuming a 4,000 metre 75 day well, about 2 tonnes per day.

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4.4.9.7 Noise

Recent studies have documented sound levels from drilling rigs operating in Alberta (Beak Consultants Ltd., 1978). Rig noise was recorded as moderately high at the edge of the lease area (68 to 73 dBA at less than 20 metres from the rig), decreasing to natural background noise levels (low 30's) at distances of approximately 1,000 metres from the drill site. Sound attenuation is expected to be greater for Arctic rigs due to the extensive enclosures around them. Consequently, noise levels should be lower than those described.

4.5 OIL AND GAS PRODUCTION SYSTEMS

The drilling activities used to locate hydrocarbons in geologic formations and to delineate the size of reservoirs were discussed in Section 4.4. This section describes the facilities required to effectively move fluids, under controlled conditions, from the subsurface reservoir to processing facilities, where the crude oil and gas are prepared to meet product specifications for transportation via tanker and/or pipeline. Processing facilities are designed to safely and efficiently separate oil, gas, and water and remove sand produced with the oil.

The equipment required for producing and processing oil and gas will be designed by facilities engineers employing the skills of process, mechanical and electrical engineering. The basic data provided to the designers include expected production rates for each well and for the field throughout its producing life, fluid characteristics and compositions, and environmental operating and limiting conditions. The facilities will always be designed with cost, safety and reliability as key factors.

As the Beaufort Sea-Mackenzie Delta Region is a remote location, the production facilities will necessarily be totally self-sufficient, requiring water treatment and utility systems, safety systems and personnel accommodation. A description of these ancillary systems, necessary to support the oil and gas production facilities, is included in this section.

Production facilities, whether located onshore or offshore, will include the same production equipment and ancillary facilities, with differences related primarily to use of space, layout of producing wells at the surface, and construction logistics.

The facilities applying to oil and gas production will be described in the general sense with major differences between the offshore and onshore locations being highlighted. Offshore production facilities will typically be located on artificial islands as conceptualized in Figure 4.5-1; whereas, a production facility onshore will be subject to fewer space restrictions as shown in Figure 4.5-2.

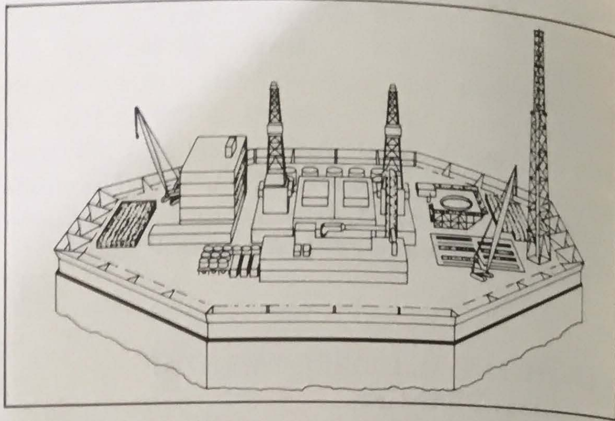

FIGURE 4.5-1 *After a discovery has been made and its commercial viability has been established, permanent drilling and production facilities are installed on suitable foundations. This conceptual drawing shows the arrangement of production equipment on an offshore island.*

4.5.1 WELL COMPLETIONS

As described in the section on drilling systems, the final drilling procedure involves setting casing through the producing horizon and cementing it in place. In a conventional land operation in southern Canada, a drilling rig is moved off the well at this stage, then a smaller rig, called a workover rig or service rig, is moved into place to complete the well. The heavy hoisting and drilling equipment provided with the drilling system is no longer required since the tubulars used in the completion activities are smaller and lighter.

In most offshore applications, however, it is not practical to remove the drill rig and replace it with a workover rig, so the completion operations are carried out by the drilling rig and the drilling rig crews. This will be the case for offshore producing wells and may also occur onshore.

After a production well has been drilled, it must be completed so that the oil and gas can be moved under control from the producing formation to the surface. Well completions typically involve running the production tubing inside the well casing, installing the wellhead control equipment, perforating the casing into the producing formation, and chemically or physically stimulating the formation to increase the flow of oil.

Perforation is the process of piercing the casing wall to provide holes through which the formation fluids may enter. Perforation of the casing is often done by lowering bullet perforators to the desired depth and electrically firing bullets through the casing and into the formation. This causes very little damage to the

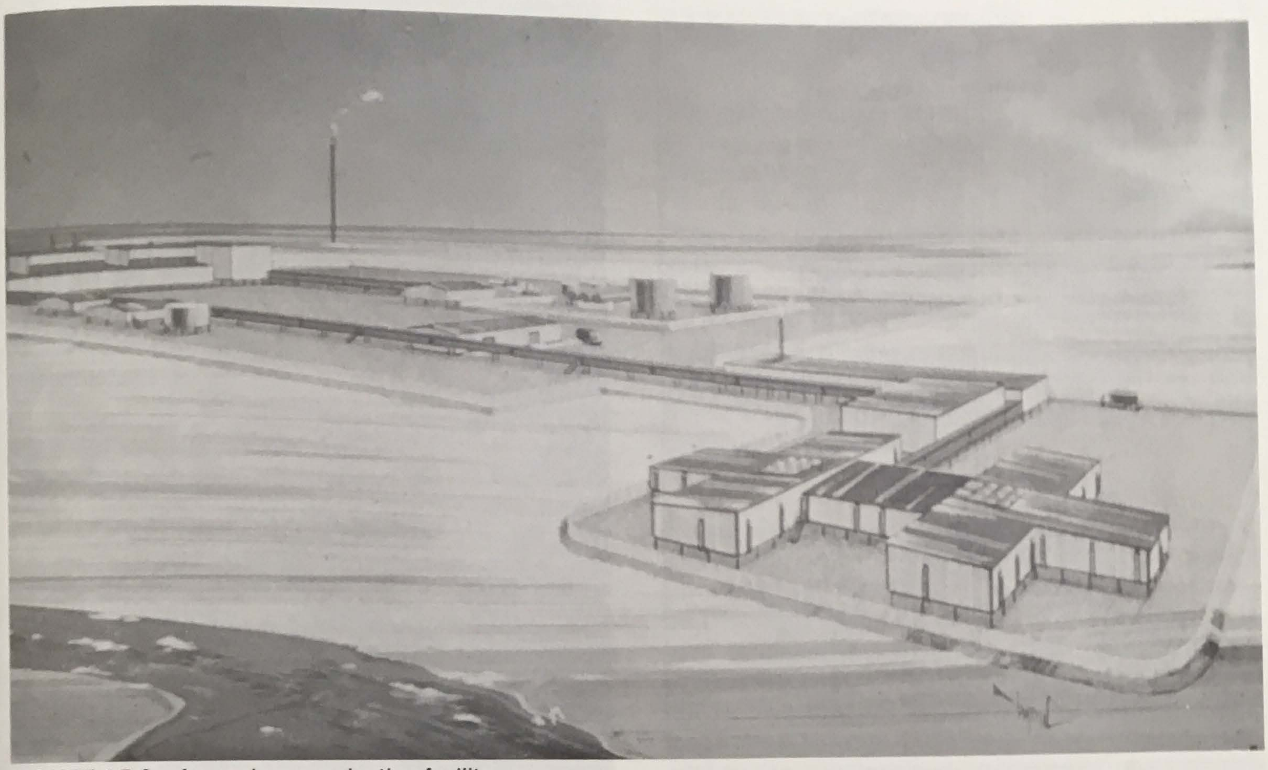

FIGURE 4.5-2 *An onshore production facility.*

casing and produces a smooth round entrance hole to provide for a maximum oil flow rate with a minimum of perforation. Three to six metres of the section can be perforated at a time, or multiple units may be used to perforate a longer section of pipe. Perforating is a standard operation and is done in the same way both onshore and offshore and in either oil or gas wells.

The succeeding steps in well completions are dependent on wellbore and formation conditions. If the reservoir rock is unconsolidated, it may be necessary to take steps to prevent the sand grains from the reservoir rock from flowing into the wellbore along with the reservoir fluid. Although a certain amount of sand production can be tolerated, excessive sand can lead to problems with surface equipment and also necessitates frequent workovers or cleanouts of the wellbore, as described in Section 4.5.5.

This type of problem is expected in wells in the Beaufort Sea-Mackenzie Delta Region. The common procedure to remedy the situation is to 'gravel pack' the wellbore. Gravel packing involves placing a filter of carefully sized and sorted gravel or sand between a liner, placed inside the production casing, and the perforated production casing. The liner has carefully machined slots throughout its length to prevent passage of the gravel. Thus, the gravel restrains the movement of the formation sand and the slotted liner prevents displacement of the gravel. Figure 4.5-3 illustrates a wellbore where the production casing has been perforated and the liner gravel packed in place.

From this point, the equipment and procedures used in well completions are determined by well depth and reservoir pressure. In conventional land operations with shallow wells, low reservoir pressures and small volumes of gas associated with the oil, the equipment and procedures are very simple. After perforating the well, the tubing string would be run into the well and the well placed on production. In higher pressure situations, where the wells are capable of flowing oil to the surface without any artificial lift, a packer may first be run into the well. The packer, as shown in Figure 4.5-3, is a device which isolates the perforated section of the producing casing from the upper sections of the wellbore. The tubing is set in the packer before it is set in the wellhead.

All offshore wells are equipped with packers. Perforation into the producing horizon is performed after the packer is in place. A smaller perforating gun is run through the tubing string into the open casing below the packer.

Well completion operations, as well as workover operations, are always conducted with fluid or drilling mud of sufficient weight in the hole to control pressure.

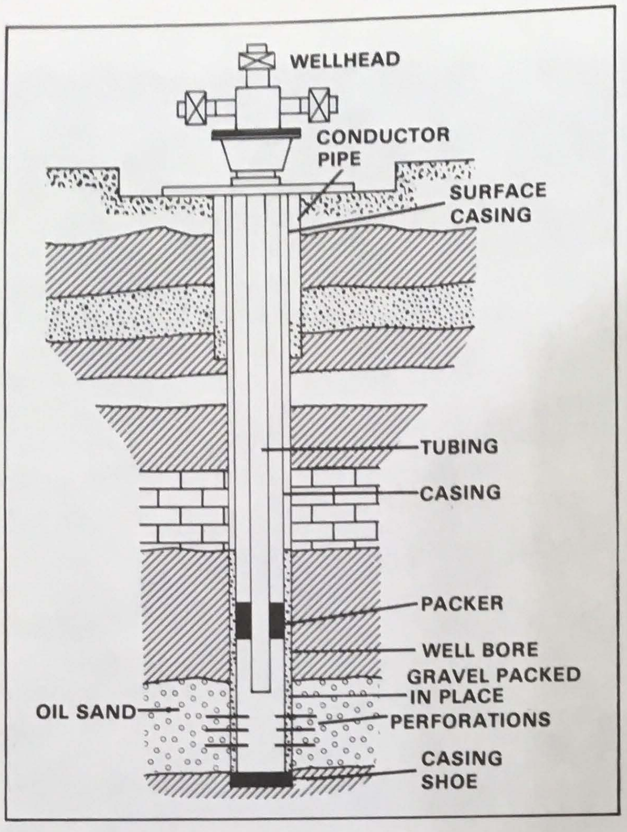

FIGURE 4.5-3 *Illustration of a well bore where the production casing has been perforated and the liner gravel packed in place.*

Wellbore hydraulics deal with the geometry of the producing tubulars. The combination of the geometry of the tubulars, the characteristics of the reservoir rock and the reservoir fluid determine the producing characteristics of any well. The producing characteristics of the reservoir are determined by the permeability of the rock, the thickness of the section, the fluid viscosity and reservoir pressure. All of these factors, except pressure, are more or less constant, so one can actually draw a curve that relates formation producing capability with bottom hole pressure; the lower the bottom hole pressure in a well relative to reservoir pressure, the higher the production rate. Once the fluid has entered the wellbore it begins to flow up the tubing string. The flow rate up the tubing string is dependent on well depth, fluid characteristics, including viscosity and density, and the diameter and roughness of the pipe. Another variable is the pressure that is held at the surface, called back pressure. By matching the producing characteristics of the tubing string with the producing characteristics of the reservoir, one can accurately predict well performance.

The design of the tubing string actually controls the design of the entire well bore. For example, if one wanted to produce 1,600 cubic metres per day from a depth of 3,000 metres, it would likely require a tubing string diameter of about 10 cm. The casing string would therefore have to be a minimum of 17.5 cm, which in turn dictates the diameter of the other casing strings.

A number of devices can be included in the tubing string to improve the safety of the production operation. These include such things as the mud line suspension system, which enables the tubing to be suspended within the casing, from a point below the well head. In the case of Beaufort Sea-Mackenzie Delta wells it is probable that this type of a hanger system will be employed below the depth of the permafrost. If any permafrost related problems occurred the tubing string would remain intact. Another device is a tubing shut-off valve which, in the case of offshore wells, is installed below the sea floor. These devices originated in the Gulf of Mexico where they are called "storm chokes," suggesting that if the production platform was destroyed by a storm, the wells would be automatically shut in at a level several metres below the sea floor. The wellhead control equipment, consisting of control valves, pressure gauges, and chokes, is called the "Christmas tree" and is assembled at the top of the well to control the flow of oil and gas as shown in Plate 4.5-1. Christmas trees in the Beaufort Sea-Mackenzie Delta Region will be located either on land or on artificial islands, with the exception of possible subsea completions, where the wellhead control equipment is placed at or below the sea floor.

The final operation in preparing the well for production is to displace the fluid in the annular area with a non-corrosive fluid to protect the production pipe from corrosion.

4.5.2 CRUDE OIL PRODUCTION

Oil present in an underground reservoir contains dissolved gas and is almost always associated with a certain amount of water. When it rises to the surface the pressure is gradually reduced. At lower pressures the oil will hold less dissolved gas so the surplus is evolved as free gas. Water may not be produced along with the oil and gas mixture in the early phases of oil production, but in the final phases when the field may be water-flooded to improve the recovery, water is also produced.

4.5.2.1 Oil Field Development

The fundamentals of oil field development have been described in Section 4.2. The design of hydrocarbon recovery systems is a function of many subsurface characteristics, as described, and the layout of the production wells at the surface varies considerably, depending on offshore or onshore locations.

Offshore, as many as 50 production and injection

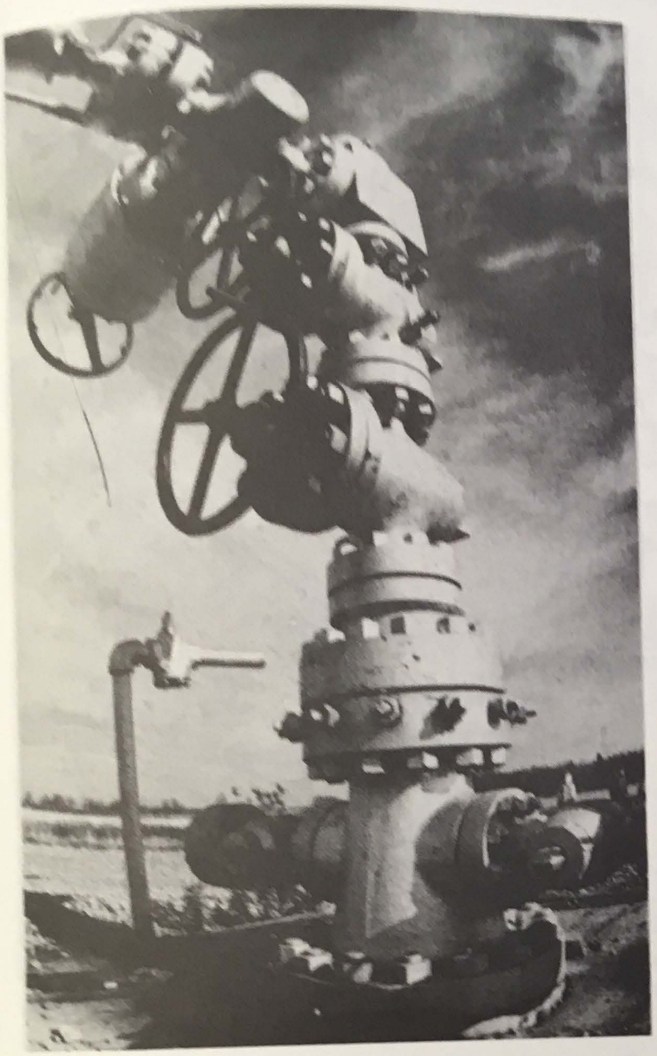

PLATE 4.5-1 *The 'Christmas tree' is a series of valves used to control a producing well.*

wells may be drilled from a production island and may be spaced as close as 3 metres apart. All but one of these wells will be drilled directionally to enable oil recovery from locations considerably distant from the production island. In some offshore oil fields, additional production and injection wells will be drilled from satellite islands or will be completed subsea, with product transmission by subsea pipeline to a central production island.

An onshore oil development will consist of one or more well clusters which will produce oil to a central production facility. The wells in a cluster will be drilled directionally to the subsurface target area with a spacing at the surface of about 30 metres. Metering and test facilities will be provided at each well cluster. Oil well fluid will be transmitted through short flowlines to central processing facilities. Similarly, injection lines will be run to injection wells at the clusters for the injection of water or gas. Figure 4.5-4 illustrates the surface facilities at a typical onshore oil field development.

4.5.2.2 Crude Oil Processing

The physical separation of oil, gas and water is the primary function of a crude oil processing system. In addition to achieving fluid separation, the production facility must also include equipment and processes for dealing with the separated gas (associated gas), for treating and disposing of produced water, for storage and distribution of the produced oil, and for removal of other unwanted substances such as sand. Figure 4.5-5 shows the typical crude oil processing components, the gas use alternatives, produced water treatment facilities, and the storage and distribution components.

Before entering one of the process trains in an oil processing system the incoming well fluid passes through an inlet manifold. The manifold is a specialized combination of pipe valves and fittings which is used to route flow from a number of wells to the process equipment. The manifold also has the capability of isolating one well's flow stream and directing it to a test separator. Data from the test separator are vital to the planning and implementation of strategies to ensure the most efficient depletion of the oil reservoir.

Normally, the initial and simplest type of processing equipment in any production facility is a series of separation vessels. The progressively lower pressure in each vessel allows gas and water to be separated from the oil. In a three phase separator, the gas rises to the top of the vessel, the water falls to the bottom, and the oil remains in the middle. The effluent oil is directed to storage, the water treated for disposal, and the gas treated and used for fuel, compressed for reinjection, directed to the distribution network or flared. Plate 4.5-2 is an illustration of a three phase oil separator.

Sometimes some of the water produced with the oil is not 'free' and it is necessary to apply additional processing to the oil in order to remove it. The water exists in the form of an emulsion. Typically, after initial water separation, the remaining water concentration in the oil stream would be less than 2% or 3%. This remaining water is separated by adding surfactant chemicals to the stream and by heat, sometimes aided by an electrical process. The equipment used for this additional processing is a pressure vessel very similar to the separator previously described and is called a heater-treater. These vessels are almost always operated at a very low pressure (200 to 350 kPa) and accordingly are larger than gas separators. The effluents from this vessel consist of gas which is

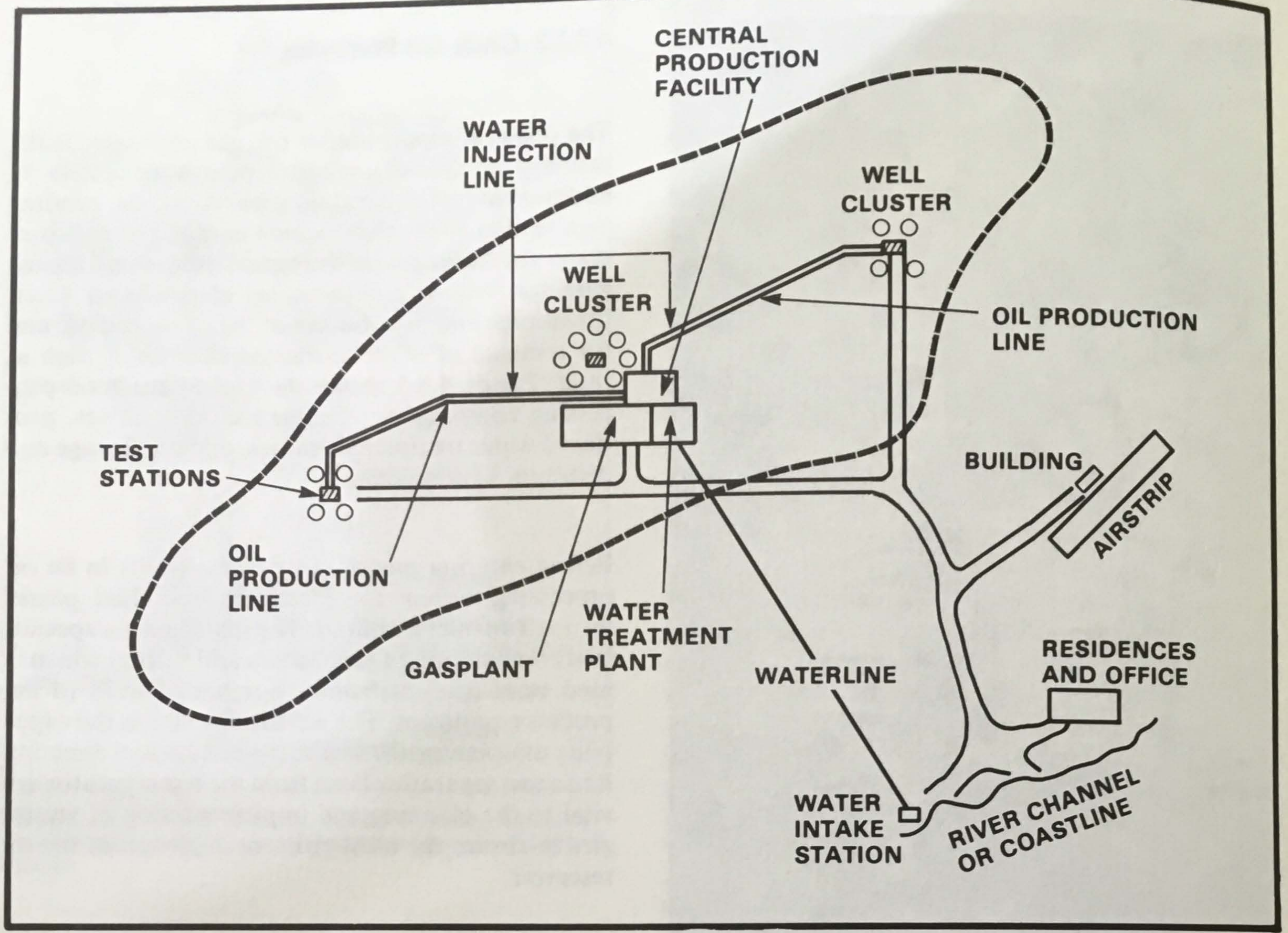

FIGURE 4.5-4 *Production systems include wellheads, production flow lines, oil and gas processing systems, water injection lines, and support facilities.*

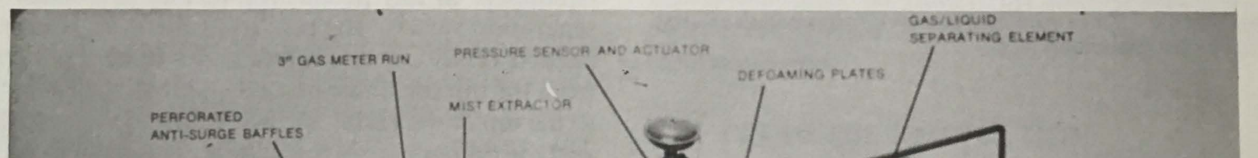

PLATE 4.5-2 *A typical three phase oil separator which processes reservoir fluid by separating the gas and water from the oil.*

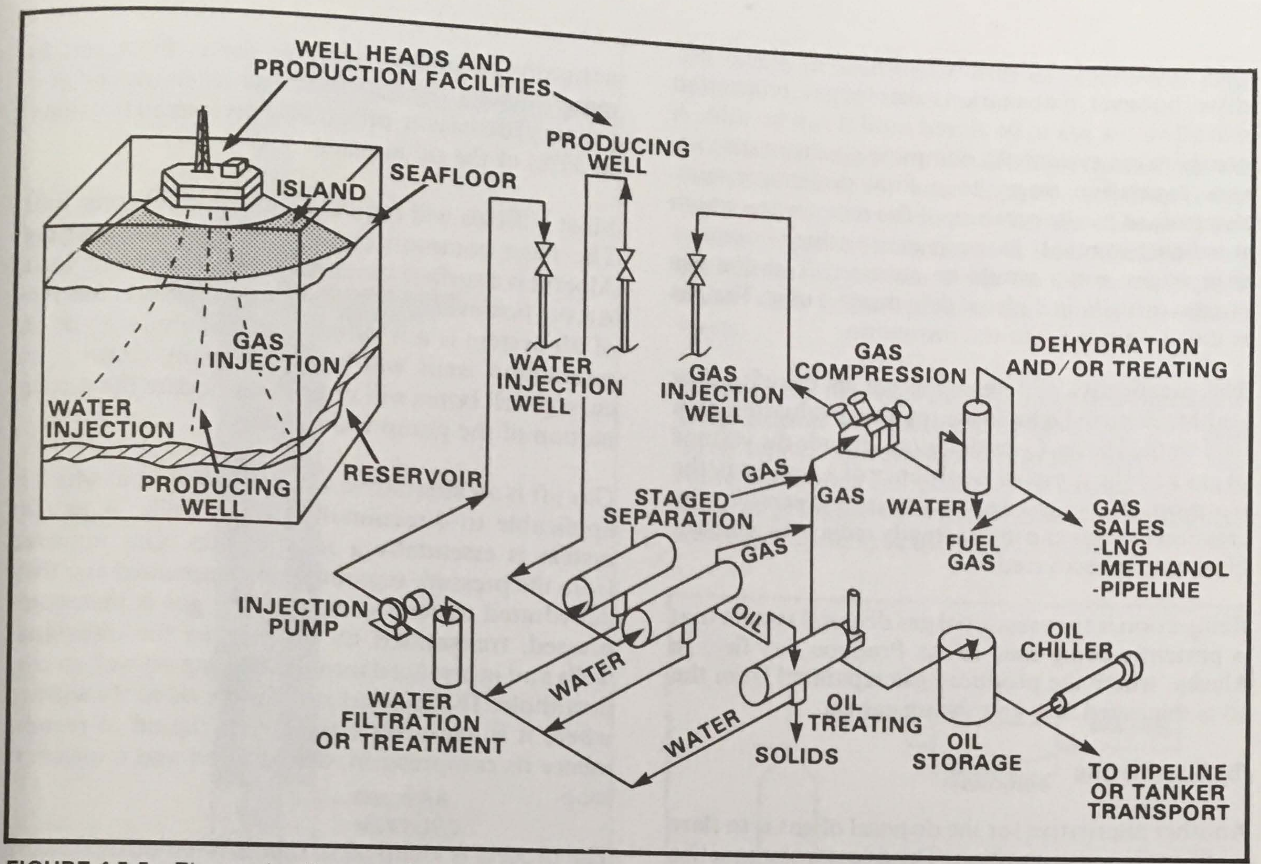

FIGURE 4.5-5 *The crude oil processing components, gas use alternatives, production water treatment facilities and the storage and distribution components of a crude oil processing unit.*

removed at the top, oil which is removed in the middle, and water which is removed at the bottom.

4.5.2.3 Associated Gas Use Alternatives

It is expected that, at a typical oil development, about 178 cubic metres of gas would be produced per cubic metre of oil. This associated gas will be treated for use as fuel within the production facility, compressed for reinjection, compressed for transport to market or flared. These alternatives are shown schematically in Figure 4.5-6.

The volume of associated gas depends on oil production rates and the gas-oil ratio. An oil production rate of 16,000 cubic metres per day will produce approximately 2.8 million cubic metres of associated gas per day.

In conventional installations, associated gas is treated, compressed and delivered to gas pipelines. This option will not be available in the early phases of development of the Beaufort Sea-Mackenzie Delta Region.

The alternative uses for associated gas are discussed in the following:

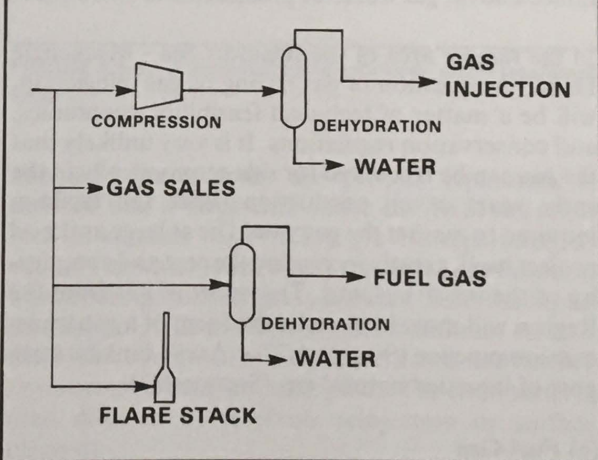

FIGURE 4.5-6 *Associated gas use alternatives include: gas injection, gas sales, fuel gas, and gas to flare.*

(a) Reinjection

Generally, oil recovery can be increased by maintaining reservoir pressure through the injection of water and/or gas. Where markets exist for the gas, water injection would be chosen, provided there is an adequate supply. Water drive is more efficient than gas

drive; however, if no market exists for gas, reinjection will allow the gas to be stored until it can be sold. A compression system will compress gas from the various separation stages to a final design pressure, determined by the pressure of the reservoir to which it is being injected. Between intermediate compression stages, water would be removed from the gas stream, usually in a glycol dehydration unit. The gas is then reinjected into the formation.

The practicality of reinjecting gas in Beaufort Sea and Mackenzie Delta fields requires evaluation on a field by field basis. Considerations include the volume of gas and the presence or absence of a gas cap in the reservoir. If no gas cap exists in a reservoir, the creation of a gas cap may actually reduce the amount of oil that is recovered.

Reinjection is the associated gas disposal system that is presently being used in the Prudhoe Bay field in Alaska, where the produced gas separated from the oil is reinjected into an existing gas cap.

(b) Gas Flaring

Another alternative for the disposal of gas is to flare it after primary separation. This is common practice in the Middle East and in several offshore fields in the North Sea, where a sales gas line is not available and reinjection is not economically or technically feasible. When a natural gas export system becomes available, flaring of associated gas would be discontinued and the gas would be processed and distributed.

In the remote area of the Beaufort Sea - Mackenzie Delta, the question of gas flaring or gas reinjection, will be a matter of technical feasibility, economics, and conservation regulations. It is very unlikely that the gas can be recovered for sale economically in the early years of oil production, since the facilities required to market the gas would be as large as the oil project itself, greatly increasing the cost and complexity of the initial systems. Transport of gas from the Region will most likely take the form of a gas transmission pipeline (Section 6.2) or Arctic tanker transport of liquefied natural gas (Section 6.3).

(c) Fuel Gas

Fuel gas for gas turbines, oil heaters, oil treaters, glycol water heaters, and emergency generators will be supplied after intermediate gas compression. This gas would pass through a fuel gas scrubber and through pressure control valves prior to use as fuel.

(d) Artificial Lift

The energy of associated gas under pressure in the reservoir is probably the most valuable withdrawal mechanism for oil. Primary recovery of oil uses this naturally occurring reservoir force. However, for many reasons, the reservoir may reach the end of its primary life,having produced only a small fraction (5 to 30%) of the oil in place.

Most oilfields will require artificial lift at some time. The most common method in Saskatchewan and Alberta is a surface mounted sucker rod pump. In the Arctic, however, and particularly offshore, this type of lift system is not suited since the majority of the production wells will be directionally drilled. The curved well bores will not accommodate the vertical motion of the pump rod system.

Gas lift is an alternative artificial lift system which is applicable to directionally drilled wells. A gas lift system is essentially a recycle loop. Gas removed from the pressure separators is compressed and then dehydrated to remove water. The gas is then compressed, transmitted by pipeline to the individual wells and introduced into the flowing oil well stream downhole. The injected gas lifts the oil to the surface where it is again separated from the oil to recommence its compression, dehydration and reinjection loop.

The process is identical to that in a naturally flowing well. The mechanics involve providing the proper volume of gas, injected at the right place, at the right pressure - an area of engineering which in itself has become very specialized. Figure 4.5-7 illustrates the components of gas lift system.

Artificial lift is not all that common in offshore installations. Artificial lift increases the cost of operation substantially. These costs, when combined with the other high fixed and variable costs associated with offshore operations,frequently render an offshore field uneconomic.

4.5.2 Disposal of Produced Water

Early in the life of an oil field, there will be very little water produced with the oil. Eventually, however, water will be produced and toward the latter half of the life of the field it will likely be produced in large quantities. In a field that is 20 years old, it is not unusual for a stream produced from the wellbore to contain more than 80% water.

Methods selected for disposal of produced water are usually totally dependent on economic and operational considerations. For conventional land production, produced water is almost always processed and reinjected into the reservoir. There are two reasons for this: the water is usually saline and there is no practical way to treat it for disposal on the surface; and water production, like oil production, usually causes the reservoir pressure to decline. Since pres-

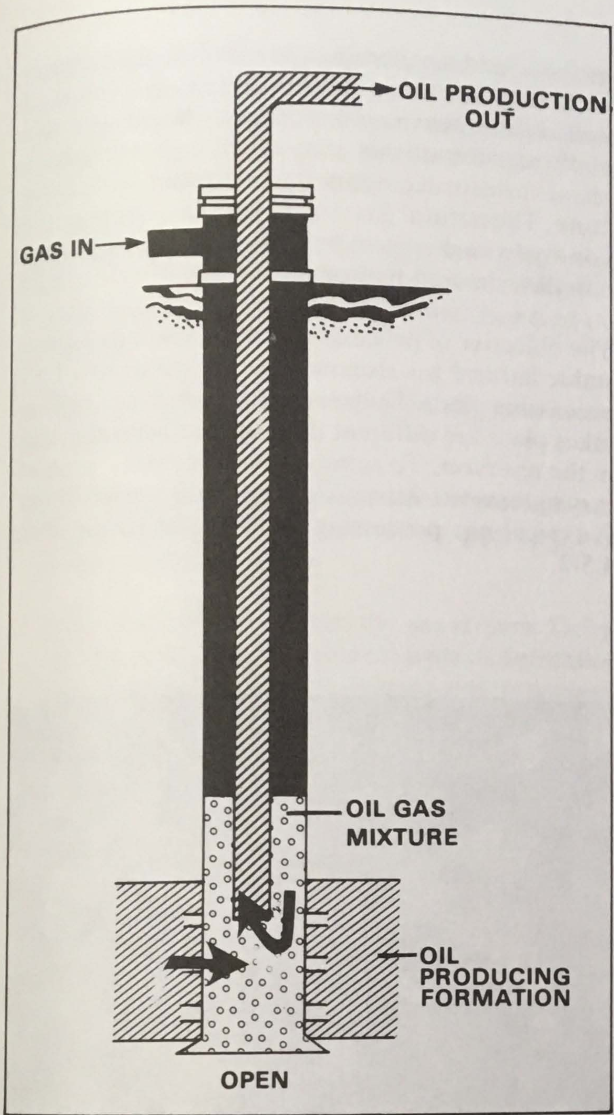

FIGURE 4.5-7 *Natural gas is injected into the well bore to lift oil to the surface from the producing formation.*

sure maintenance is important, each unit of fluid produced must be replaced with a unit injected. Produced water is usually cheaper than other sources for production on land so it becomes quite practical to reinject the produced water along with make-up sources if available. Nevertheless, produced water disposal is still a significant operating cost and will be a contributing factor in determining the profitability and abandonment point of any oil field.

In offshore operations, the methods selected for disposal of produced water will depend on the configuration of the production process and the characteristics of the oil well fluid. In Cook Inlet, Alaska, free water is separated offshore and the remaining water, which is difficult to separate, is transported to shore along with the oil through a subsea pipeline system. The additional water is removed onshore. It was not practical to send the water back to the platforms for reinjection since this would have required another pipeline so the water is treated and disposed of into the ocean in accordance with environmental regulations.

In Cook Inlet, as in most offshore operations, the source of water for water injection schemes is sea-water since it is available in copious quantities and usually requires little treatment. It is, therefore, more economical to use sea water for all water requirements than it is to process and reinject produced water.

Onshore oil fields in the Beaufort Sea-Mackenzie Delta Region will undoubtedly have their produced water treated and reinjected into the reservoir. Offshore operations will probably be carried out in the same way. Figure 4.5-8 is a schematic of a produced water treatment system.

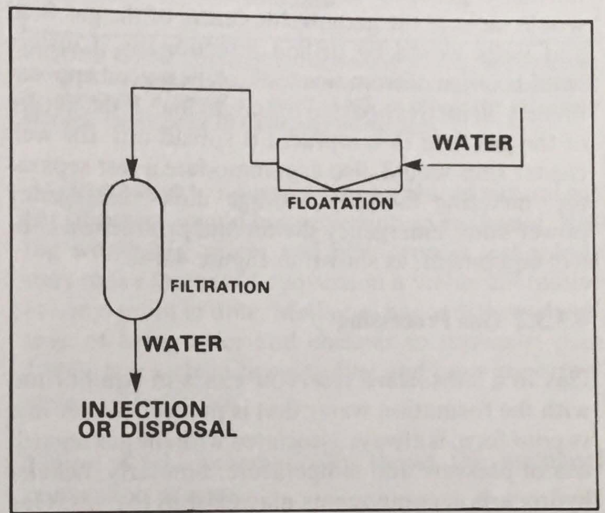

FIGURE 4.5-8 *A schematic of a produced water treatment system.*

Produced water from the process separators is directed into a surge tank where sufficient retention time is allowed for primary gravity separation to occur. The water is drawn off through a gas flotation unit where produced gas is released from the liquid throughput. The produced water continues on to a filter where removal of suspended solids and further removal of oil droplets takes place. The clean water is then directed to reservoir reinjection or surface disposal.

After treatment, facilities required for the injection of water to the reservoir consist of injection pumps, a piping system, and associated instrumentation to control injection rates and pressures.

4.5.3 GAS PRODUCTION

Proven reserves of onshore gas, coupled with further anticipated onshore gas discoveries, represent significant quantities of gas available for development.

Although preliminary indications point to oil production being the primary product for offshore development, it is anticipated that major non-associated gas fields will be discovered and commercially developed. At this stage of development, associated gas previously injected into oil reservoirs will be recovered and directed to natural gas processing facilities by subsea pipelines.

4.5.3.1 Gas Field Development

Non-associated gas field development offshore, would not differ significantly from offshore oil field development in terms of well spacing on artificial islands. An onshore gas development would consist of clusters of gas wells, a gas plant and support facilities normally grouped in one location. Well clusters would be near the geographic centre of the gas field and wells would be drilled directionally. Clusters would consist of from two to six wells spaced approximately 30 metres apart in a straight line. If the nature of the gas field development is spread out, the well cluster sites would also accommodate a test separator, metering facilities, storage tanks, emergency power units, emergency shelter and production control equipment, as shown in Figure 4.5-9.

4.5.3.2 Gas Processing

Gas in a subsurface reservoir exists in equilibrium with the formation water that is present. Water in a vapour form is always associated with the gas regardless of pressure and temperature. Similarly, heavier hydrocarbon components may exist in the gas. One normally thinks of natural gas as being 100% pure methane but it is usually a mixture of predominantly methane and smaller quantities of heavier hydrocarbons such as ethane, butane, propane, pentane, as well as some heavier components. The concentration of these components that remains in the gaseous phase varies in accordance with pressure and temperature. The natural gas stream may also contain some non-hydrocarbon components such as nitrogen, carbon dioxide, and hydrogen sulphide.

The objective of processing natural gas is to deliver a stable natural gas stream to a pipeline or to a LNG processing plant. The pressures at which this delivery takes place are different than the pressures that exist in the reservoir. To achieve this objective, it is necessary to remove excess water and other hydrocarbons. A typical gas processing facility is shown in Plate 4.5-3.

PLATE 4.5-3 *A gas production facility.*

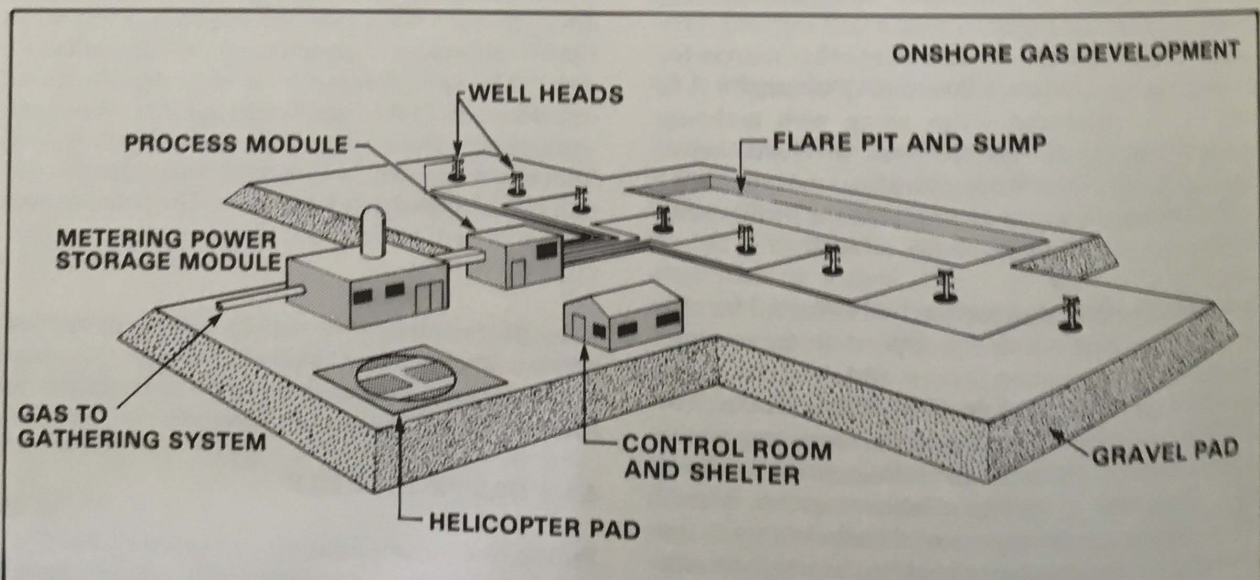

FIGURE 4.5-9 *A well cluster site accommodating a test separator, metering facilities, storage tanks, emergency power units, emergency shelter and production control equipment.*

Natural gas processing includes the removal of excess water, carbon dioxide, hydrogen sulfide and liquid hydrocarbons from the raw gas, and subsequent compression and cooling to produce a gas which meets transportation requirements.

Each well stream would be brought into a metering building in individual flowlines and manifolded to a common production header which will then feed the processing system.

The processing of raw gas will typically involve the following operations:

1. Separation of the raw gas stream into gas and liquid phases at the separation pressure and temperature conditions.

2. Removal of water from the gas stream. Dehydration is necessary to prevent hydrate formation (gas freezing) within the subsequent processing steps or during transportation, and also to minimize the possibility of corrosion. The gas will be dehydrated by glycol or a solid desiccant absorption process.

3. Removal of heavier hydrocarbons that may condense to a liquid in the transmission line. The condensate removed could be used as a fuel within the gas production facility, injected into the crude oil system or reinjected into the producing formation.

4. Removal of carbon dioxide, if present, by chemical liquid absorption. Carbon dioxide is not a physical problem as far as handling is concerned but, since it has no heating value, transporting it is a wasteful use of energy and capacity. In the unlikely event that hydrogen sulphide were to be present in the gas stream, it would be removed by chemical liquid absorption. The recovered gases would be incinerated and the resultant sulphur dioxide would be released from an elevated stack.

Further treatment of the gas is a function of the method used for transmission to market. Assuming a pipeline transportation system, the gas would be compressed to the pipeline transmission pressure. Compression requirements would depend upon the reservoir pressure, processing scheme, and ultimately the pipeline requirement.

If a tanker option were utilized to move natural gas from the Beaufort Sea-Mackenzie Delta Region, the gas product would be compressed to the liquid state. A liquefaction plant, as shown schematically in Figure 4.5-10, having the capability of chilling the gas to about -160°C, would be constructed in the development area. The liquefied natural gas would then be transported by icebreaking LNG tankers to a southern re-gasification plant for conversion back to natural gas.

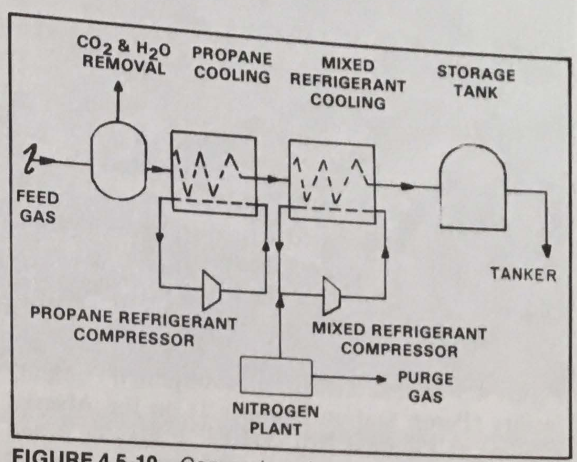

FIGURE 4.5-10 *Conversion of natural gas to LNG involves removal of carbon dioxide and water and cooling to -160° C to generate a liquid product. LNG is stored in insulated storage tanks prior to transport by tankers.*

An alternative to liquefying the produced natural gas for shipment would be conversion to methanol. Rising world fuel prices and new process technology may make methanol conversion a viable alternative at some point in time. Methanol has a further advantage of being safer and cheaper to transport than LNG. It is a clean burning fuel and is an important chemical feedstock.

Figure 4.5-11 schematically shows the methanol conversion process.

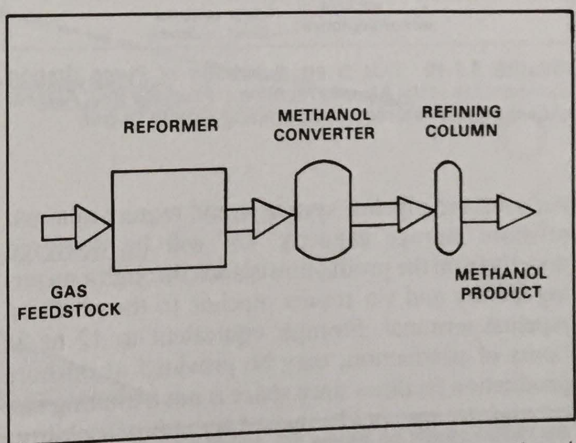

FIGURE 4.5-11 *A schematic representation of the methanol conversion process.*

4.5.4 STORAGE FACILITIES

Oil storage facilities in the Beaufort Sea-Mackenzie Delta Region will be required to minimize production interruptions caused by temporary pipeline shutdowns or the late arrival of an Arctic tanker. In

the case of the tanker option, the amount of storage is dependent on production rates, tanker capacities, and frequency of arrival. In the case of a pipeline, storage will be provided on land at the northern pipeline terminal. Storage will also be available at the southern pipeline terminal to meet daily market demand fluctuations.

4.5.4.1 Onshore Storage

Onshore storage systems will consist of conventional welded steel storage tanks. Earthen dykes surround the tanks and are designed to retain oil in the event of a spill or leak. An impervious liner is installed in the tank farm base and dykes where further protection is required.

Figure 4.5-12 illustrates the oil storage and pumping facility (Pump Station Number 1) on the Alyeska Pipeline at Prudhoe Bay, Alaska. It may be noted that only 67,000 cubic metres (420,000 barrels) of oil storage capacity is required for this system, which is designed to pump 320,000 cubic metres (2 million barrels) of oil per day.

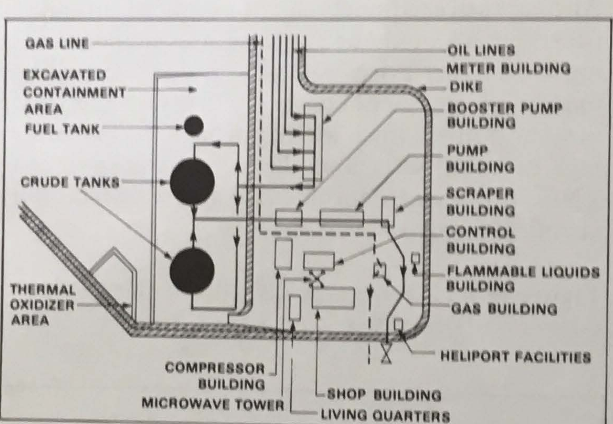

FIGURE 4.5-12 *This is an illustration of Pump Station Number One of the Alyeska Pipeline at Prudhoe Bay, Alaska, showing the oil storage and pumping facility layout.*

An overland pipeline system would require minimal offshore storage capacity. Oil will be delivered directly from the production islands through a metering facility and via subsea pipeline to the northern pipeline terminal. Storage, equivalent to 12 to 24 hours of production, may be provided at onshore production facilities since space is not a limiting factor and storage could enhance operating flexibility.

Onshore storage tanks will be constructed on gravel pads to guard against thawing of permafrost and, where necessary, the foundations may be insulated and/or refrigerated.

If oil is be transported by Arctic tankers on a large scale, one alternative under consideration is to provide tanker loading facilities at a regular port. A water depth greater than 20 metres is required for docking the icebreaking Arctic tankers, thus limiting the choice of locations for this alternative. If conventional land storage were used, tankers would dock at mooring dolphins offshore, and the oil would be delivered from the storage tanks by either a subsea pipeline to the mooring area or a pipeline on top of a finger pier connecting the mooring area with land. This type of system is used in Cook Inlet where it has been in operation for 15 years with no reported mishaps.

4.5.4.2 Offshore Storage

For the Arctic tanker option, storage could be provided offshore at the tanker loading facility. In order to provide sufficient volume of crude oil to permit fast loading of the Arctic tankers, and to provide flexibility to accommodate tanker delays, about four ship loads of storage capacity would be required per loading platform.

The storage system at an Arctic Production and Loading Atoll (APLA) could be provided by a floating barge system protected from ice forces as shown in Figure 4.5-13. Alternatively, the crude oil storage system could be submerged within the harbour of the APLA. The submerged storage tanks would be constructed of steel or reinforced concrete and would be designed to withstand hydrostatic forces.

Another system under study uses a storage island (Figure 4.5-14) containing about 960,000 cubic metres of surface storage, with the tanker loading terminals strategically located several kilometres from the island. These loading terminals would be connected to the storage island by subsea pipelines.

In the North Sea, oil is stored offshore in the base of concrete gravity type platforms. Oil from the process system on the platform flows directly into the storage compartments in the base of the platform. Tankers are loaded at some distance from the platform at a buoy which is called a single point mooring system (SPM). The empty tankers moor themselves to the SPM which has its own subsea pipeline to the platform storage. The ship is free to rotate around the SPM in accordance with wind direction. A flexible pipeline runs from the buoy to the tanker.

Another alternative still under consideration for offshore loading in the Beaufort Sea is a system similar to that described for the North Sea. Storage tanks would be constructed within the concrete caisson of the production island, for subsequent transfer by subsea pipeline to a mooring system for tanker loading. As is the case for all offshore storage, the storage facilities will be compartmentalized to increase the strength of the structure and to minimize the amount

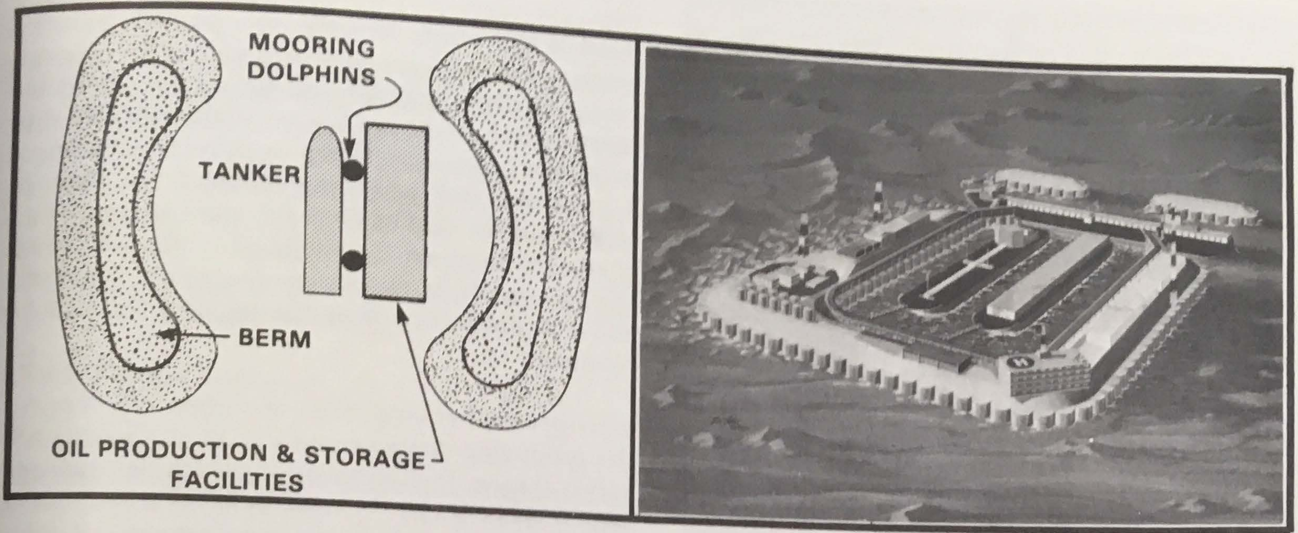

FIGURE 4.5-13 *A floating barge storage system within the harbour of an APLA and an alternative configuration with one end of the protective berms closed.*

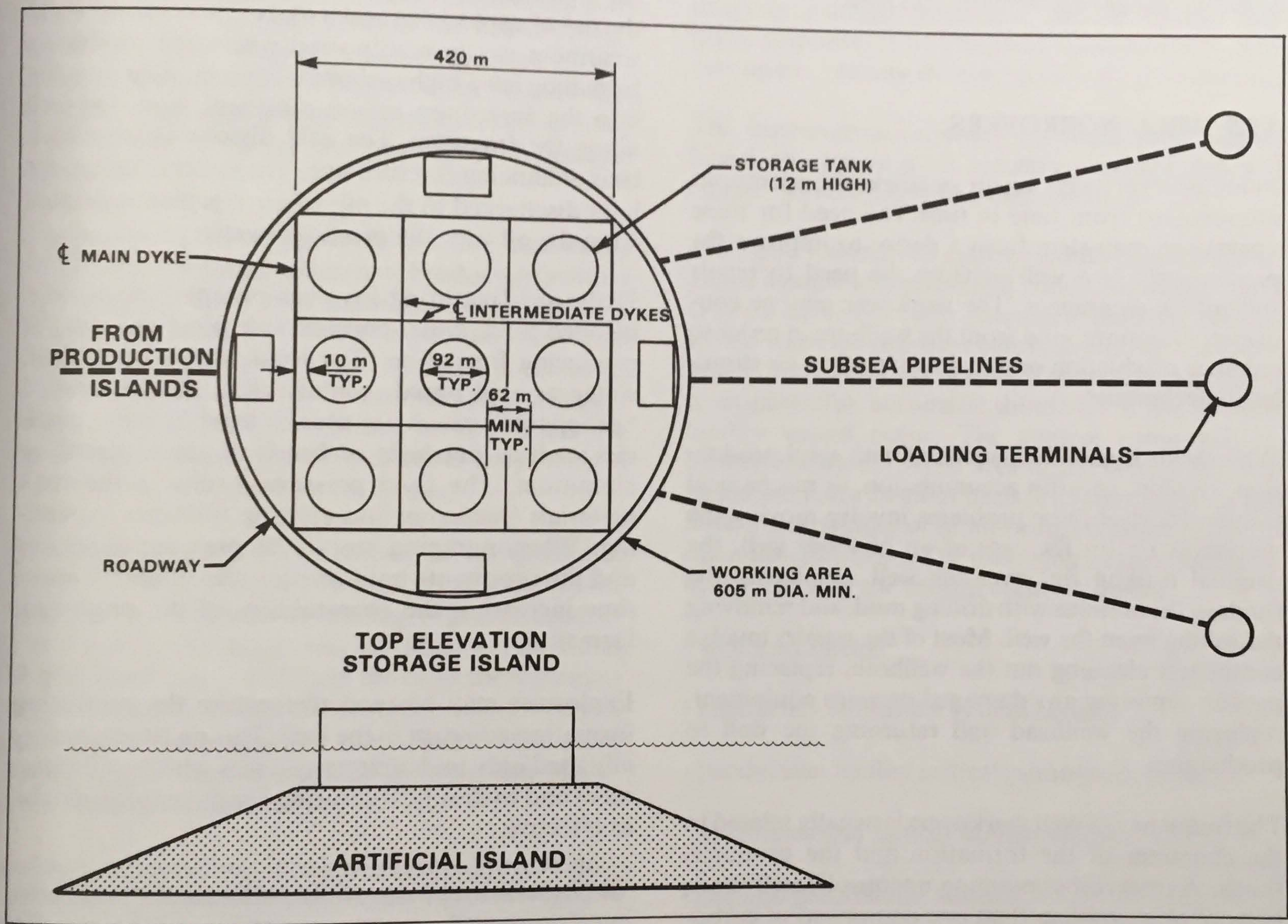

FIGURE 4.5-14 *An oil storage system under study uses a storage island as illustrated. Oil would be stored within the chambers on the artificial island then pumped via subsea pipeline to distant tanker loading terminals, as required. One or more production islands would supply oil to this storage island.*

of oil lost in the remote event of a leak. Figure 4.5-15 shows storage compartments within the base of a production platform.

4.5.4.3 Other Storage Systems

Conversion of natural gas to LNG or methanol would also require storage tank systems. In general, the same options would be available for storage of LNG or methanol; however, in the case of LNG, the storage tanks would be insulated. LNG storage systems would be located adjacent to the LNG conversion plant.

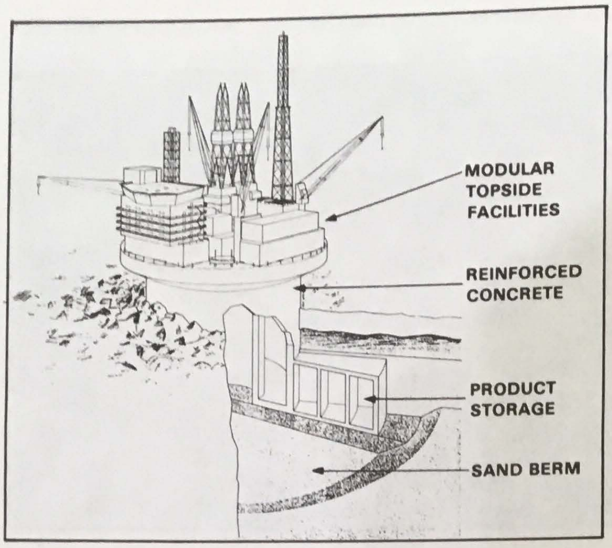

FIGURE 4.5-15 *A concrete gravity structure placed on the seabottom, similar to those used in the North Sea, might contain oil storage compartments in its base.*

4.5.5 WELL WORKOVERS

In almost every well, repair or workover operations are required from time to time.The need for these operations may stem from a desire to improve the productivity of a well or from the need to repair subsurface equipment. The workover may be conducted to remove sand from the wellbore in order to enhance production or may involve reservoir stimulation techniques.

Well repair is usually associated with sand production, erosion, paraffin accumulation, or mechanical failure. Most of these problems involve moving the workover rig (in the case of an offshore well, the original drilling rig) over the well, displacing the fluids in the annulus with drilling mud, and removing the tubing from the well. Most of the repairs involve completely cleaning out the wellbore, replacing the packer, repairing any damaged or worn equipment, replacing the wellhead and returning the well to production.

The frequency of well workovers is usually related to the character of the formation and the produced fluids. A reservoir containing unconsolidated sands is more of a problem than one comprised of carbonate rock. Fluids with high paraffin contents, and those containing sulphur, are more prone to problems than asphaltic crudes, which are free of sulphur. In Beaufort Sea-Mackenzie Delta wells, sand production and associated problems can be expected. Little corrosion, however, is anticipated since the oil does not contain any sulphur. Paraffin is also not present.

The sand related workover on an offshore well would require one or two weeks of time and one could expect to work on each well once every two years. Thus, if there were 50 wells on a producing island, workover activities would be taking place continuously. Surface facilities and operating procedures must, therefore, be carried on simultaneously with workover operations. When workover operations at a particular well are being initiated, the adjacent wells would be shut in. Once the spool piece has been connected between the wellhead of the well being worked and the blowout preventer of the drilling rig above it, production from the adjacent wells can be resumed.

At conventional land wells, workovers to improve the producing characteristics of the formation are very common. Well stimulation, which encompasses several processes used to enlarge existing fractures in a producing formation or to create new ones, is often used to enhance oil production. Chemical and physical methods of stimulation include acid treatment, the use of explosives, and hydraulic fracturing. Acid treatment is commonly used where the producing formation has a high carbonate content. Acid pumped into the formation moves outwards from the well along the fractures. The acid dissolves carbonates, thus enhancing fracture size. The neutralized acid is later discharged to the oil, where it is then separated from the oil with the produced water.

Hydraulic fracturing involves pumping a specially blended fluid, under considerable pressure, into the producing formation. The fluid, which can be oil, water or acid based, contains fine particles called "proppants" which are usually sand or other particles such as nutshells or beads of glass, plastic or aluminum. The fluid pressure results in the rock materials fracturing and existing fractures expanding. When pumping stops, the pressure dissipates and the proppants hold or prop the fractures open, thus increasing the permeability of the producing formation.

Explosives may be used to fracture the producing formation adjacent to the well. This method is generally used only under circumstances where acid treatment and hydraulic fracturing are not expected to be as effective.

Wellbore stimulation, while performed occasionally in offshore wells, is more common in onshore wells. One of the reasons for this is that these techniques are easy to apply and are more successful in poor quality wells with thin reservoirs. By nature, offshore reservoirs have thick producing sections, and are of good quality, or they otherwise would not have been developed. The thicker sections are more difficult to stimulate and require very large quantities of stimulation fluids. Thus, there is a limit to the practicality of stimulating offshore wells.

4.5.6 SAFETY SYSTEMS

Safety systems protect personnel, equipment and the environment from injury or damage. These systems will be addressed in great detail in the plan of development submitted to the regulatory authority for approval prior to each oil field development. They are addressed here mainly in the context of concept and policy. In this regard, it should be noted that each operator has developed and regularly updates safety and contingency plans and procedures for all types of safety-related incidents.

4.5.6.1 Fire and Explosion

The oil industry has many years of experience in handling volatile products where the danger of fire and explosion is ever present. The growth of the offshore oil industry caused even more attention to be directed to this hazard since the means of escape are reduced and equipment and investment are concentrated in a very small area. In the Beaufort Sea-Mackenzie Delta Region, whether onshore or offshore, all systems will be designed using state-of-the-art technology and include substantial redundancy to absolutely minimize the possibility of fire and explosion.

Design criteria are comparable to those used in the aircraft and aerospace industries. Producing facilities are typically divided into spaces in accordance with their susceptibility to fire and explosion. Any area where there is a source of hydrocarbons is classified as a hazardous area and, accordingly, stringent design and operating conditions prevail. These are areas where failure of a valve or vessel may result in the emission of flammable oil or gas.

Petroleum Industry design standards, designated as API R.P. 500 B entitled "Classification of Areas for Electrical Installations at Drilling Rigs and Production Facilities on Land and on Marine Fixed and Mobile Platforms," will form the basis for determining area classifications for installations. However, good engineering practice may dictate that more stringent guidelines be used for Beaufort Sea-Mackenzie Delta developments.

Safety systems in hazardous areas include preventive systems, which automatically control the atmospheric Preventive systems include such things as ventilation systems which automatically control the atmospheric pressure in a hazardous area to a lower pressure than the surrounding areas. Other preventative measures include specifications of electrical equipment to exclude any fittings or devices which are not explosion-proof.

Alarm systems include such things as gas alarms which would immediately detect the presence of gas before it had reached an explosive level. The alarm would alert operating personnel to the condition and could also be used to activate a mitigating device such as a well shutdown. Flame detectors indicate the presence of a source of ignition, even though there may not be any flammable substances in the hazardous area. Other alarm devices indicate overheating, overspeed conditions, abnormal pressure, abnormal flow rates, and a host of other extraordinary circumstances. All of these alarm devices automatically initiate corrective action, as well as notifying the operating personnel of the existence of a particular condition.

4.5.6.2 Control Systems

Operating a Beaufort Sea-Mackenzie Delta production facility efficiently and safely will involve correct functioning of sophisticated instrumentation for achieving process control. The control system will be properly planned to achieve precise control and quick response. It will respond immediately to process upsets and any changes in operating conditions.

The instrumentation control systems used will be based on approved oil industry practices and will employ standard certified equipment.

Emergency shutdown systems would be provided to guard against any abnormal condition which could create a hazard or cause equipment damage. Alarms would warn the operator before shutdown to enable him to take corrective action. If the corrective action is unsuccessful, automatic shutdown of the relevant facility would occur. The control room will be located within the safest area of the facility and will be manned on a 24-hour basis. The control room will have the capability of monitoring all prime platform operation functions. The following systems would be integrated into the central control console:

- wellhead status

- emergency shutdown system control

- production facility critical parameters status

- ancillaries and critical utilities status

- fire and gas systems status

4.5.6.3 Gas Flaring

Whether a production installation is designed for oil or gas processing, provisions must be made for safe gas disposal of some, or all, of the produced gas through relief systems to a flare during start-up, shutdown, some maintenance situations and in emergencies. During these periods the gas will be transported a safe distance from the production facility

before being burned in a flare. The primary function of the flare is to ensure complete and safe combustion of produced gases.

Proven flaring techniques allow for the safe, efficient ignition of gases. Flare tip designs have also been developed with the specific intent of ensuring complete, continuous combustion, minimization of radiant heat and significant reduction in noise levels.

The facilities selected for the Beaufort Sea-Mackenzie Delta Region will incorporate these systems with particular emphasis placed on: reliability, flare location, impact of adverse wind direction, prevention of permafrost and sea ice thaw, and personnel safety.

4.5.6.4 Exposure to Environmental Elements

One hazard that everyone associates with work in the Arctic is personal exposure to the elements. The Inuit have coped with this problem for years with relatively primitive facilities. In the north of today, exposure incidents are rare, partly because of availability of equipment and facilities for protection, and also because of general public awareness and concern for the problem. Thus, individuals always wear or have available the proper clothing and carry emergency equipment when appropriate. Designers build buildings and other facilities to protect the individual from the elements.

Operators who develop energy resources in the Beaufort Sea-Mackenzie Delta will continue to use established practices to provide personal protection from the elements. These include procedures which require all people travelling to the Arctic to have proper Arctic clothing in their possession, training in preventing and treating hypothermia, survival training for emergency conditions and the provision of appropriate emergency equipment. Permanent facilities will offer even more protection than the temporary facilities that are used in exploratory operations, consequently workers within permanent facilities will often work in a 'shirt sleeve' environment.

4.5.6.5 Well Control

The obvious hazard that must be addressed is the uncontrolled flow of fluid to the surface during the production phase. Section 4.4 describes in detail the steps that are taken during drilling to control pressures and fluid flow. During production, the need to provide safety systems to prevent a blowout situation remains.

Completion and workover operations are conducted with drilling mud in the hole, which serves the same function of well control as it does during the drilling operation. The production packer at the bottom of the hole isolates the producing reservoir from sections above. The packer provides isolation, both when the tubing is set into the packer, and when it is withdrawn. A subsurface hanger is used to suspend the tubing string below the surface. This device is supplementary to the hangar in the wellhead, and provides complete assurance that the tubing will remain properly suspended in tension, even if some catastrophic occurrence destroyed the wellhead.

The subsurface safety valve is the modern version of the valve that was once called the 'storm choke'. The storm choke was a device that was actuated when flow rates through a tubing string exceeded a predetermined critical rate. The new devices are hydraulically actuated, with hydraulic pressure applied by a small diameter line from the surface. Hydraulic pressure keeps the valve open during normal producing operations. A release of hydraulic pressure causes the valve to close automatically. This arrangement makes the operation of the valve fail-safe; that is, if a catastrophic event occurred at the surface, the source providing hydraulic energy for the subsurface safety valves will be destroyed and the wells will automatically close. These valves can be operated manually simply by cutting off the source of hydraulic pressure.

4.5.7 UTILITY SYSTEMS

Utility systems are the facilities which provide the necessary support for the oil and gas producing systems, the drilling systems, and the subsurface systems. They include electrical power generation, compressed air supply, fire-fighting capability, personnel accomodations and services, potable water supply, source water supply and sewage treatment.

In conventional land-based oil field operations in southern Canada, utilities do not present much of a problem. The power systems and communication systems are commercially available and other utilities can be readily provided. In remote areas on land or offshore, the operator usually must provide all the services; therefore, oil and gas production facilities in the Beaufort Sea-Mackenzie Delta Region will include all required utility and ancillary facilities.

4.5.7.1 Source Water Treatment and Injection Systems

The quantity of source water taken from the sea for offshore development will be determined largely by the production process cooling needs and the supplementary injection volumes required. Source water for onshore production facilities will be obtained from nearby fresh water sources.

If water in addition to produced water is used for injection purposes, it is important that the water be treated to prevent formation plugging. This generally entails the use of a filtration system to exclude detri-

mental particles. Water required for injection may be further filtered using sand filters, diatomaceous earth filters or cartridge filters. The water then passes through a deaeration tower which reduces the oxygen content to 0.5 parts per million. The remaining oxygen level may then be further reduced through the addition of chemical agents to levels of 25 parts per billion. Additives to minimize corrosion in the injection wells and preserve the reservoir formation deliverability characteristics are commonly used. Booster pumps take the water from the deaeration tower to feed the high pressure injection pumps. The main injection pumps will have a discharge capability corresponding to the particular reservoir injection requirements.

Similarly, water used for process cooling will be filtered to remove suspended solids, to minimize fouling of the distribution, cooling and utility systems. In addition, a chemical biocide is often injected into the system to inhibit biological growth.

4.5.7.2 Production Fuel Source

Hydrocarbon gas taken off the main process will be the main fuel source at an oil production facility. In order to power emergency generators, fire pumps, cranes, drilling equipment and other critical components and life support systems, a supply of diesel fuel will be maintained.

At gas production facilities, plant condensate will be used as the normal fuel supply, and natural gas will be used as back-up during turbine start-up and shutdown. The processed natural gas would serve as an emergency fuel gas supply.

During the construction phase of oil and gas production facilities, diesel fuel will be the primary fuel source and will be utilized until after commissioning.

4.5.7.3 Instrument and Utility Air

Clean, dry instrument and utility air is essential for the operation of production facilities, control and instrumentation systems. A typical installation would use a compressor, pre-filter, air compressor and receiver to supply the required volume of air at a nominal utility pressure of 150 psig. Drying equipment would also be selected to provide a constant, reliable source of clean dry air.

4.5.7.4 Heating Systems

Each separate facility will require a heating system. Generally, heating requirements would be met by waste heat recovery from turbine exhausts, with direct fired heaters being used during commissioning and as an operational emergency back-up. Maximum use will be made of waste heat in meeting the heat load requirements at Beaufort Sea-Mackenzie Delta production facilities.

4.5.7.5 Electrical Power Generation

Electrical power will be generated at each site by turbine drive generators. In general, most equipment, such as oil pumps, gas compressors, water pumps, auxiliary motors, etc., will be electrically driven.

As is common practice in the oil industry, the capacity to supply 100% standby emergency power to assure system reliability will be installed. Thus, for lighting, living quarters heating, communications equipment, and all essential and emergency systems, a standby generator will be provided with a diesel fuel drive and sufficient fuel to last through an emergency condition. All of the communication and instrumentation systems will be provided with an emergency back-up system.

4.5.7.6 Accommodation Facility

A permanent feature of Beaufort Sea-Mackenzie Delta production facilities will be modern prefabricated accommodations and services buildings. They will house the plant complements, which may range from 65 to 150 personnel, depending on the location and nature of the facilities, and the number of drilling systems. In addition, they may support part-time construction and support personnel on a regular basis. Accommodation facilities will be built from prefabricated modules and will be self-contained. They will be able to operate, with moderately restricted services, for about 30 days without outside supplies. During normal operation the facilities will be supplied with potable water from either desalination systems for seawater, if located offshore, or from watercourses nearby onshore facilities. Sufficient storage volumes of potable water will be in place to provide adequate quantities during normal or unexpected shutdowns of the water treatment system. Water treatment will typically include filtration, chemical flocculation, sedimentation and disinfection in a modular treatment plant.

The wastewater treatment system for use during construction and operation of production facilities would treat all domestic wastes which are generated. These will be primarily from kitchen, showers, toilets, and laundry. All process area wastewater would be collected separately for processing within the production plant components. The design capacity of the treatment system will include a surge capacity equal to the daily flow, in order to accommodate the daily peaks associated with morning and evening shift changes. It is anticipated that extended aeration treatment plants, or units of similar sewage treatment efficiency, will operate at production facilities. After

biological treatment and solids settling, the effluent will be subject to disinfection, if deemed necessary, prior to discharge to nearby watercourses or to the sea.

Excess sludge from the sewage treatment system will be periodically removed and either incinerated or incorporated into the solid waste handling system.

Solid waste, generated from the accommodations and services facilities, as well as that generated from the packaging of replacement parts, will be approximately 86% combustible. Consequently, on-site incineration will consume most of the soild waste, with the remainder transported to a sanitary landfill site.

4.5.8 CONSTRUCTION

The foundations for either onshore or offshore producing and drilling systems are designed specifically to accommodate the oil and gas producing facilities, drill systems, and related accessories. Because of the remoteness of the Arctic, innovative approaches for matching surface facilities to the foundations are required. Experience in other areas of the world has shown that simply placing large equipment and components on their foundations at the site of an oil field, and carrying out all of the interrelated hookup work on site is expensive and time consuming. Modular fabrication at specialized plants before transportation to the site has developed as an alternative. Each module consists of major pieces of mechanical equipment such as engines, compressors or pumps mounted on a skid-type of foundation and completely outfitted with all the accessory piping and instrumentation and controls. The entire facility can be divided into a series of these modules. Thus the field work is generally reduced to placement of the modules on the field foundations and connection.

The modular approach to facility construction has been so fine-tuned that fabrication plants all over the world have been built specializing in fabrication of modules. The larger the module the better; however, the limit on module size is dictated by the ability to handle the module at both the fabrication site and the field site.

In the Beaufort Sea-Mackenzie Delta Region there is room for substantial innovation in optimizing the modular approach towards facilities construction. The benefits will be enormous, since construction costs in this remote and harsh environment are approximately an order of magnitude higher than other oil producing areas of the world. The Arctic Production and Loading Atoll (APLA) concept described in Section 4.3.6.5 provides the designers with a number of attractive options for modular design. It is possible that an entire oil and gas producing system will be fabricated on a single barge in a shipyard in the south. Such a barge could be either anchored in place in a floating mode, or ballasted to rest on the dredged berm of an APLA. A similar concept could be used on a production island. Plates 4.5-4, 4.5-5, and 4.5-6 illustrate modules used in North Sea applications.

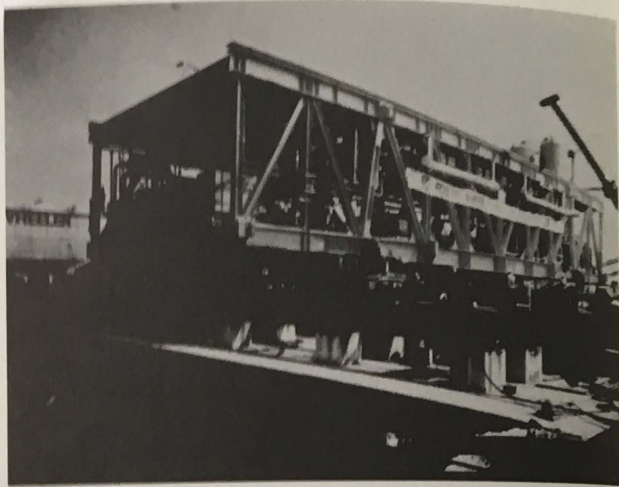

PLATE 4.5-4 *The Piper 'A' platform modules for use in the North Sea nearing completion in a fabrication yard. Courtesy of Foster Wheeler Petroleum Development (Canada) Ltd.*

All Beaufort Sea-Mackenzie Delta installations will comply with the applicable codes, standards and regulations. Due to the unique nature of this development work in the Arctic, there may be certain items that fall outside the scope of existing practices. In such cases, design standards will be established in concert with regulatory agencies.

Specific details of installation of process modules will be determined at the time they are designed and built. Both the support structure and the process unit will be unique to each location.

Permanent docking facilities will be constructed at offshore platforms immediately upon completion of the island construction. The dock will be sized to accommodate the largest supply vessel or barge expected at the island throughout the construction and operation phases. Equipment such as cranes will be sized to handle the heaviest equipment modules.

As with offshore facilities, equipment and facilities for onshore facilities will be prefabricated and shipped to the site in large modules. These modules, some possibly weighing up to 900 tonnes each, will be sized to fit the transportation units available. The modules will be transported to the site by barge and moved from the dock to their final location by crawler transporters. The dock size will be determined to a large extent by the size of the barge required for the construction phase of the project. Sizing of the dock

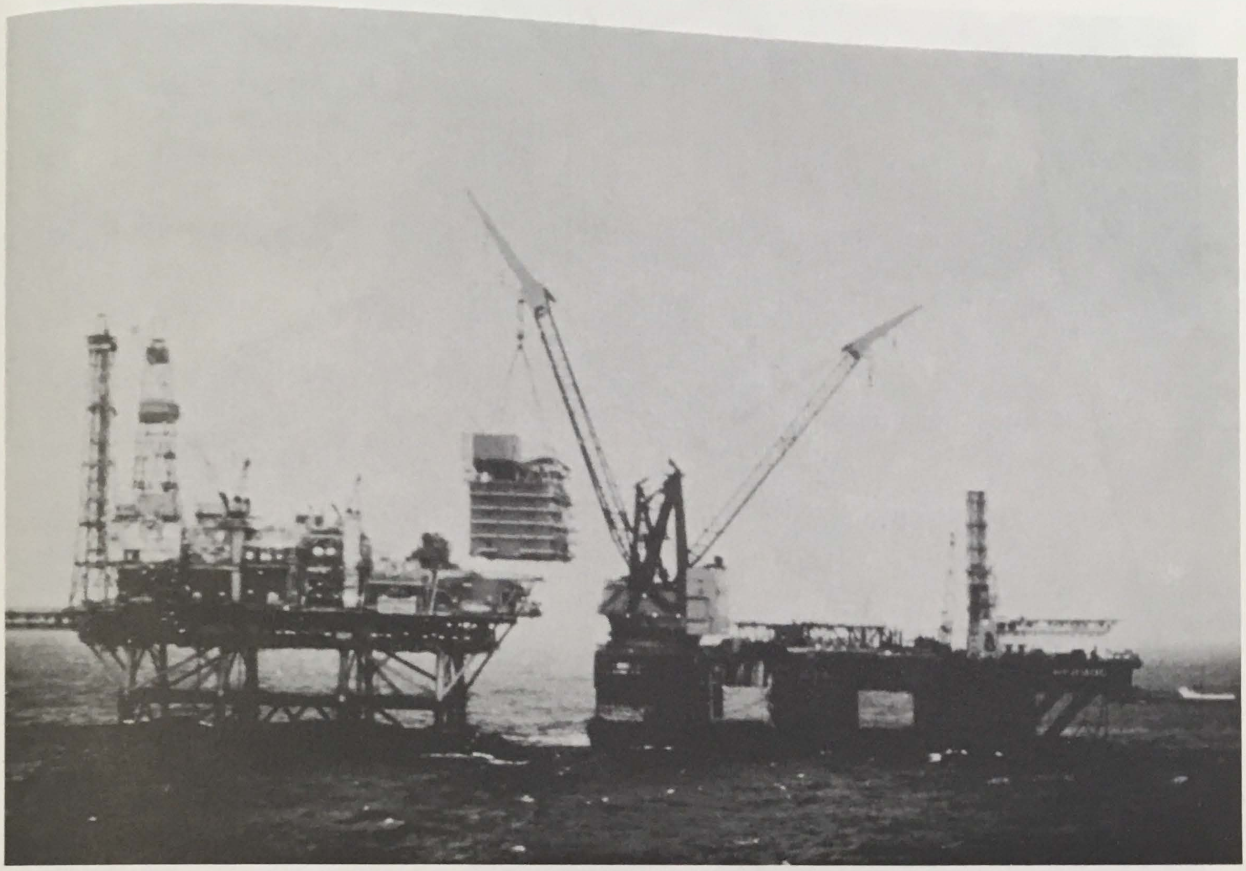

PLATE 4.5-5 *Installation of a module on the Shell Fulmar North Sea platform by a crane barge.*

will take into account the number and sizes of barges, method of unloading, location of raw water pump-house and ease of movement around the area. The permanent operating phase will require facilities and space to off-load cargo from river barges. Staging areas will be needed to store unloaded materials in preparation for the construction phase.

Installation will include interfacing, testing and commissioning the prefabricated modules, erecting buildings and installing the interconnecting piping, controls, and instrumentation from the wells to the plant itself.

Based on maximum use of modules, site construction for a typical production facility should require approximately 300 to 500 specialized tradesmen at any one time.

Construction camps will be specifically designed to be both portable and self-sufficient. Construction camps are discussed further in Section 5.3.

4.5.9 POTENTIAL ENVIRONMENTAL DISTURBANCES

This section provides a summary of the major discharges and emissions from oil and gas production systems. Potential disturbances associated with the construction of and physical presence of the foundations for production systems are discussed in Section 4.3.8. Volume 4 examines the potential impacts associated with oil and gas production systems in detail.

4.5.9.1 Atmospheric Emissions

Most equipment at oil and gas production facilities will be electrically driven; hence, products of hydrocarbon combustion for power generation will be the largest atmospheric emissions from oil and gas production facilities. Gas from intermediate separation will fire the power generation turbines at an oil production facility. The composition of expected exhaust gases is summarized in Table 4.5-1. Other activities will generate similar air emissions. Plant flares, which are used to burn off gases during emergency situations or during some maintenance procedures, will be continuously operated with a stream of natural gas.

If gas is reinjected to the formation during early development of an oil field, an additional source of air emissions will be the gas fired compressors.

The remaining source of emissions to the atmosphere will be the incinerators, which will burn up to 86% of the solid waste generated at the oil and gas processing facilities.

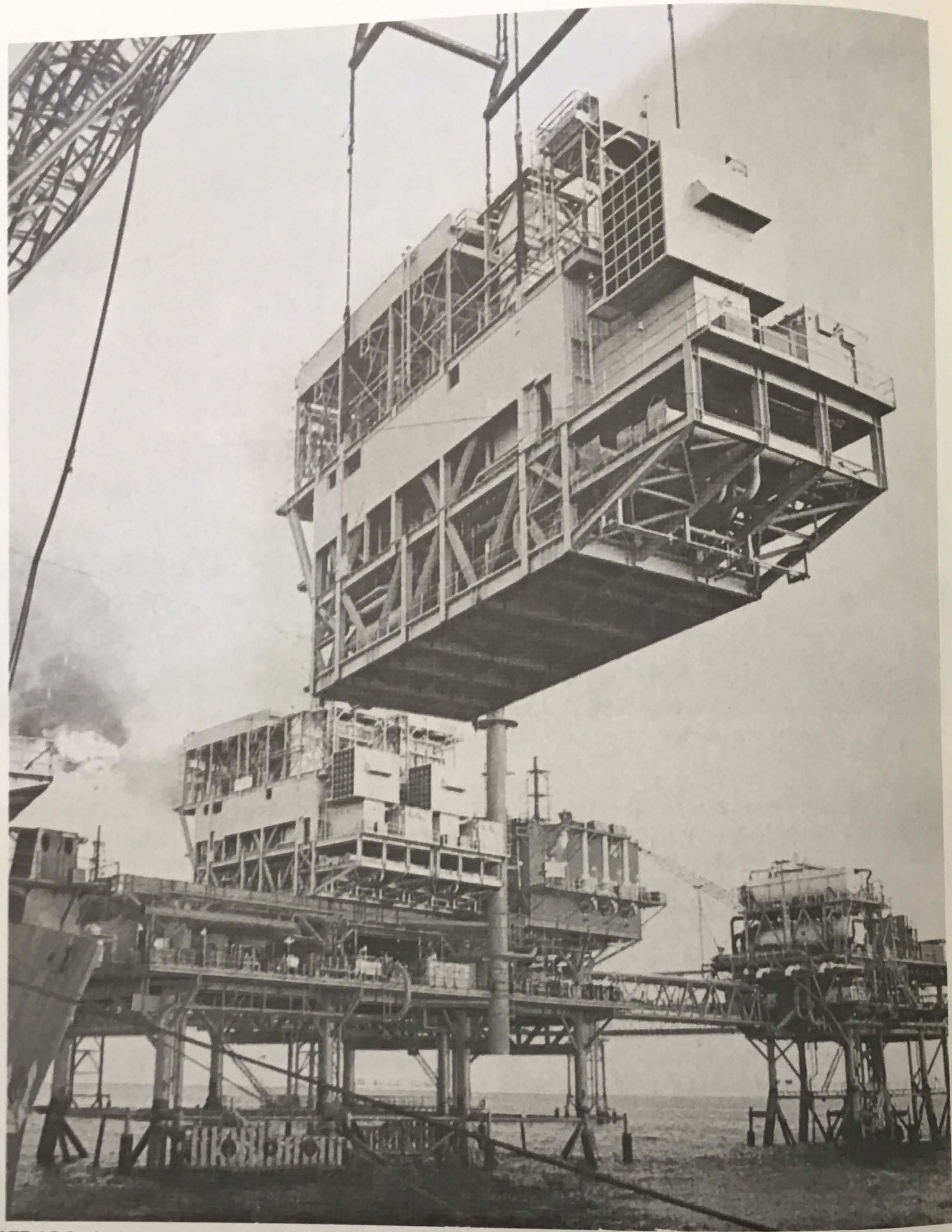

PLATE 4.5-6 *Installation of a module on a production platform.*

Other minor emission sources may include separate natural gas fired heaters at remote well sites and flowline heaters. Vehicles and heavy equipment operating at the production facilities, all likely diesel powered, will also contribute to air emissions.

4.5.9.2 Liquid Effluents

Water removed from the oil well fluid within the pretreatment system will be treated through settling, filtration and deaeration. Virtually all of the pro-

TABLE 4.5-1

FLUE GAS COMPOSITION - NATURAL GAS (Based on 50% excess O_2)

Component	Mole %
CO_2	6.5
O_2	6.4
H_2O	14.6
N_2	72.46
NO_x	0.04

duced water will be reinjected to the producing formation for pressure maintenance. The quantity of produced water is dependent on the percentage of water in the oil well fluid; however, late in the production life of a reservoir it may reach 80%.

Although unlikely in most instances, treated produced water may be discharged to the Beaufort Sea or to watercourses near onshore facilities. Residual oil and other contaminants will be removed to achieve compliance with regulatory standards prior to disposal.

Sewage effluent from accommodation units will represent a discharge to the Beaufort Sea or to watercourses nearby onshore facilities. Treated effluent will be discharged at a rate ranging from 15 to 50 cubic metres per day, depending on the number of personnel required for the drilling systems, production systems and maintenance operations.

The source water treatment plant which provides additional water for injection, potable water and a water supply for the boiler will produce a sludge which will be discharged back to the source of supply. For an onshore facility where the source of supply is fresh water, the sludge will consist of suspended and settleable solids removed from the supply. Production facilities using seawater as a source will, in addition to the above, discharge reject water from the desalination unit. Effluent from the desalination unit will contain high levels of dissolved solids such as sodium, potassium, chlorides and sulphates.

4.5.9.3 Noise

The main sources of noise at production facilities are the drilling and workover rig machinery, aircraft, and process plant equipment. The noise levels from drilling systems will be similar to those experienced at exploratory drilling operations, while aircraft noise will be a function of the type of aircraft and frequency.

Production plant equipment will be designed to comply with prescribed noise emission standards.

4.5.9.4 Solid Waste

The noncombustible portion of solid waste generated within the accommodation unit will amount to an estimated 100 kg/day and will be deposited in a sanitary landfill.

Sewage sludge, if not incinerated, will be incorporated into the solid waste stream.

4.6 SUBSEA PIPELINES

The discovery of oil offshore at Tarsiut, Koakoak, Kopanoar, Issungnak and other locations, has prompted the oil industry to develop preliminary engineering design criteria and operating procedures which will ensure the safe production and transportation of hydrocarbons from this area. The design criteria and operating procedures will reflect the special requirements for this environment. Satellite wells located on artificial islands will be connected to central production facilities via subsea pipelines systems. These small diameter pipelines will be used for oil gathering, water injection and gas reinjection (see Figure 4.6-1).

In the event that an overland pipeline system is constructed, relatively small onshore crude oil storage facilities will be required. Oil would be transferred from offshore islands to a coastal terminal via larger diameter subsea trunklines. If a tanker system were used, it would be necessary to connect central processing facilities with tanker storage terminals, located either offshore or onshore, via larger diameter submarine pipelines. The extent of hydrocarbon discoveries in this Region, as well as the choice of transportation mode, will determine the size and routing of the submarine pipelines.

4.6.1 SUBSEA PIPELINE DESIGN CONSIDERATIONS

The Beaufort Sea is a frontier area necessitating exceptional design and innovative installation techniques. A reasonably comprehensive data base has been compiled with respect to various environmental parameters including the effects of ice, weather, soil conditions, the susceptibility of permafrost to thawing, pipeline burial requirements to avoid or minimize the risk of ice contact, and pipeline shore approach methods. It is felt that sufficient information currently exists to allow design and engineering to proceed.

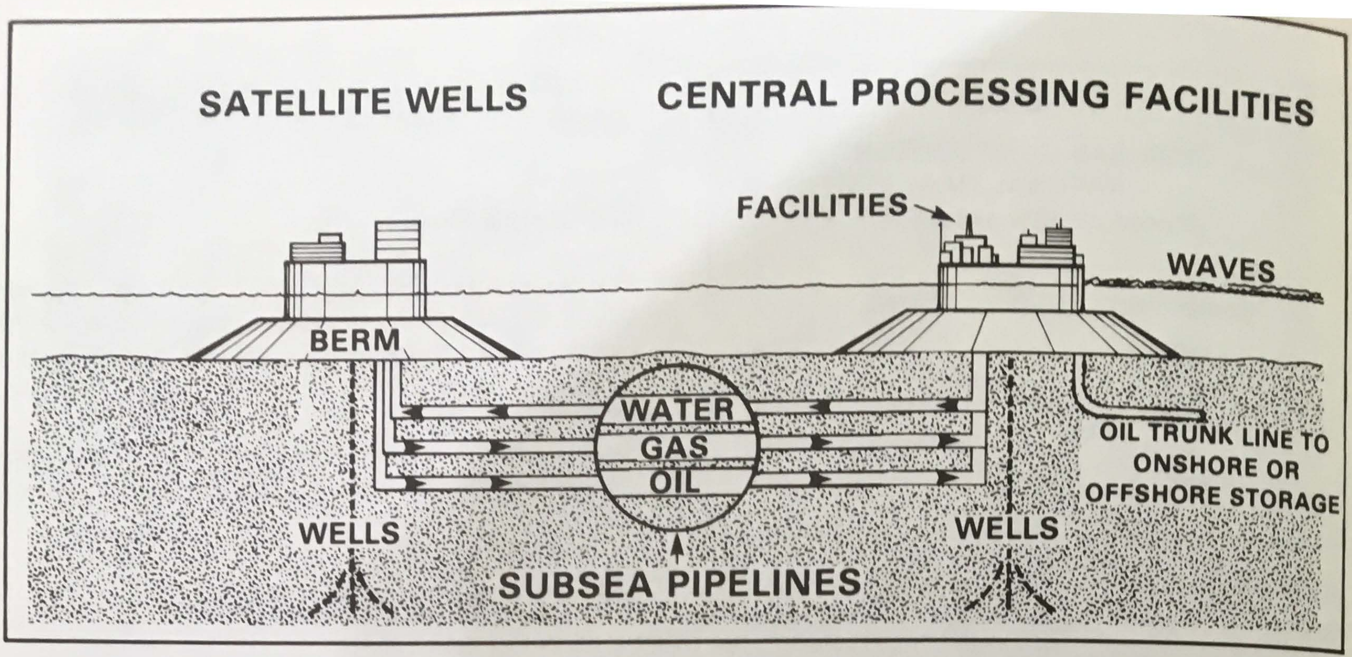

FIGURE 4.6-1 *Subsea pipelines will move oilwell fluids from satellite islands to central processing islands. Produced gas and water for injection may also be transmitted by subsea pipeline to injection wells. The produced oil or gas will then be pumped via subsea trunklines to tanker loading facilities, or alternatively to shore to a northern terminal of the overland pipeline.*

Additional data will be collected and further studies conducted to improve costs. Site-specific data gathering programs routine to offshore pipeline design are planned as specific projects are identified and include the following:

- soil sampling and laboratory testing to determine soil properties along the routes selected;

- detailed mapping of potential pipeline rights-of-way (typically 500 metres at either side of the planned pipeline centerline) with side scan sonar (seafloor mapping version);

- detailed subsea stratigraphy profiling based on borehole data and low frequency acoustic profiling.

In the following sections, the assumptions and methodology used to establish the pipeline design criteria are presented. In Volume 3, the most recent and relevant baseline data available for the parameters discussed below are reviewed.

4.6.1 Ice Scour

Echo sounding and side scan sonar equipment have been used to document the occurrence of ice scour in certain areas of the Beaufort Sea. Ice scour is caused by the grounding of large ice features such as pressure ridges and ice islands. In areas where scouring occurs, pipelines must be lowered to a sufficient depth below the original sea floor to minimize the risk of ice contact.

Based on existing data, the ice scour mechanism appears to be strongly correlated with water depth. The following discussion is therefore subdivided according to four water depth zones:

- depths greater than 20 metres;

- depths of 15 to 20 metres;

- depths of 2.5 to 15 metres;

- depths less than 2.5 metres.

The ice scour design criteria for these depth ranges are depicted graphically in Figure 4.6-2.

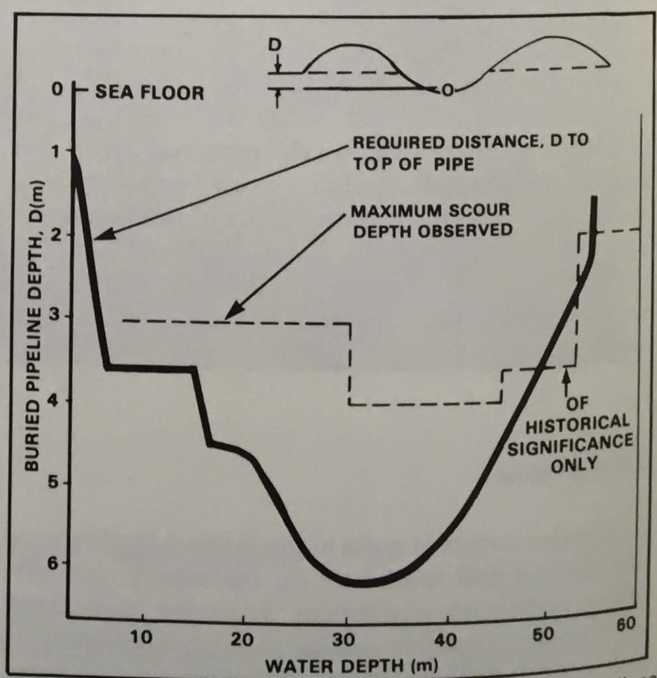

FIGURE 4.6-2 *Ice scour design criteria for subsea pipelines.*

(a) Depths greater than 20 metres

The sea floor is virtually saturated with scours in this region out to a water depth of 40 metres. Scour density diminishes rapidly in depths greater than 40 metres, essentially reaching zero at 120 metres. The scours in this zone are typically 2 to 3 metres deep. The required trench depth in this zone has been calculated based on the joint probability of ice keel impacts on the sea floor per year and the distribution of scour depths measured at various water depths (Pilkington and Marcellus, 1981). The required burial depths vary significantly in water depths between 20 and 60 metres, with the most extreme requirement (6 metres) occurring in the depth range of 30 to 33 metres (see Figure 4.6-2).

It is further noted on Figure 4.6-2 that the maximum observed scour depth exceeds the design burial depths to the top of the pipe in water depths exceeding 50 metres. Available evidence indicates that these scours occurred at a time of lower water level and are 3,000 to 10,000 years old. Based on ice keel measurements, contemporary scouring is not expected to occur in water depths greater than 47 metres, and at these depths or greater the pipe will be installed in a shallow open trench.

(b) Depths of 15 to 20 metres

In shallower water, more rapid sedimentation of the scours may cause the method of analysis used for deeper water to be less accurate. For this reason the trench depth to the top of the pipe has been established at 4.5 metres. This is based on a conservative extension of the method described above.

(c) Depths of 2.5 to 15 metres

In this depth range scouring occurs more frequently, but they are shallow, typically less than 50 centimetres deep. The design burial depth is based on the deepest scour observed (3.0 metres) plus a safety factor. For this zone, a depth of burial of 3.5 metres to the top of pipe has been established.

(d) Depths of less than 2.5 metres

For depths less than 2.5 metres, the ice is essentially bottom-fast and deep scours are not observed. A depth of burial of 3.5 metres to the top of the pipe, decreasing to 1.0 metre (minimum) at the shoreline should be adequate for ice scour protection in stable or despositional shore zones.

4.6.1.2 Permafrost

Another important consideration in the design of offshore pipelines in the Beaufort Sea is permafrost. Industry has conducted soil surveys in this Region over the past 11 years and has been able to identify the extent of permafrost in the near shore and onshore areas (see Volume 3A). Special consideration will be given to instances where the pipeline design operating temperatures exceed that of the permafrost. It will be necessary to design the lines to minimize the extent of permafrost degradation, and ensure that they will not become overstressed due to differential settlements induced by the thawing of the permafrost. There are several design procedures which can be used to achieve this end.

One method that has been proposed for the shore approaches is to place the pipelines on a bed of select granular backfill material, thereby providing an insulating layer between the pipeline and the permafrost. It is anticipated that by using this method, permafrost degradation will be mitigated or settlements will be minimized to acceptable levels (less than 2 m).

Other methods have been considered for traversing the nearshore and onshore areas containing permafrost. These include:

- artificially cooling the oil at the processing facility;

- elevating the pipeline on piles or an artificial berm; and

- circulating a refrigerant through cooling tubes surrounding a jacketed pipeline (Palmer *et al.*, 1979).

4.6.1.3 Currents

Current velocities determine the hydrodynamic forces which act on a pipeline during installation. Water circulation within the Beaufort Sea Region is relatively weak. The design current velocity, based on a four month open water season, has been calculated to be 55 centimetres per second. This low velocity will have little effect on pipeline stability, particularly since the pipe will generally be laid in a protective trench.

4.6.1.4 Seismicity

Pipeline design must also take into account the potential for seismic activity in the area. The Beaufort Sea is a region of relatively low seismic activity (see Section 4.1.3 and Volume 3A). The largest earthquake recorded to date had a magnitude of 6.7 (modified Marcelli intensity scale, 1931). The Earth Physics Branch of the Department of Energy, Mines and Resources, recommends a design horizontal acceleration of 2% g based on a return period of 100 years. Analyses conducted using a very conservative horiz-

ontal acceleration of 10% g indicate that there is little danger of slope instability or soil liquefaction in the area.

4.6.1.5 Bathymetry

The bathymetry of the Beaufort Sea slopes gently to the north and is relatively uniform.

4.6.2 SUBSEA PIPELINE DESIGN

For the purposes of demonstrating subsea pipeline design requirements, this section details the design of inter-island flowlines for transmission of gas, oil and water between offshore production islands, and the design of trunklines for the transmission of oil from Tarsiut, Kopanoar, and Issungnak to shore (R.J. Brown and Associates, 1981). It is emphasized that the following discussion is intended to serve only as a basis for demonstrating the procedures used and feasibility of installing pipelines in the Beaufort Sea. Final development plans may reflect different pipeline configurations and routings, however, the conclusions presented are considered applicable to any of the currently envisaged offshore development plans.

The following assumptions were made to determine the subsea pipeline requirements. The Tarsiut field; located in 17 m to 23 m water depths, will consist of a central processing island with a number of satellite islands each producing oil and gas. The Kopanoar field will consist of a central processing island with a satellite island, both in approximately 60 metres of water, and the Issungnak field will consist of one or two islands in 20 metres of water. Figures 4.6-3 and 4.6-4 show the general location of the subsea pipeline network needed for this example development for both Arctic tanker and overland pipeline options.

In the case of Arctic tanker transportation of oil to southern markets, one or more artificial islands will serve as a tanker loading and storage terminal, located in 20 to 30 m of water (see Section 4.5.4). In the alternative pipeline transportation case, trunklines will bring the oil and/or gas to shore to connect to the overland pipeline system at the northern terminus.

To illustrate the size of various offshore trunklines, it was assumed that 20,000 cubic metres of oil per day would be transferred from Tarsiut to either the onshore terminus or to an offshore storage terminal, that 80,000 cubic metres of oil per day would be transferred from Kopanoar to Issungnak and that the pipeline from Issungnak to an onshore terminus would require a pipeline capacity of 95,000 cubic metres per day.

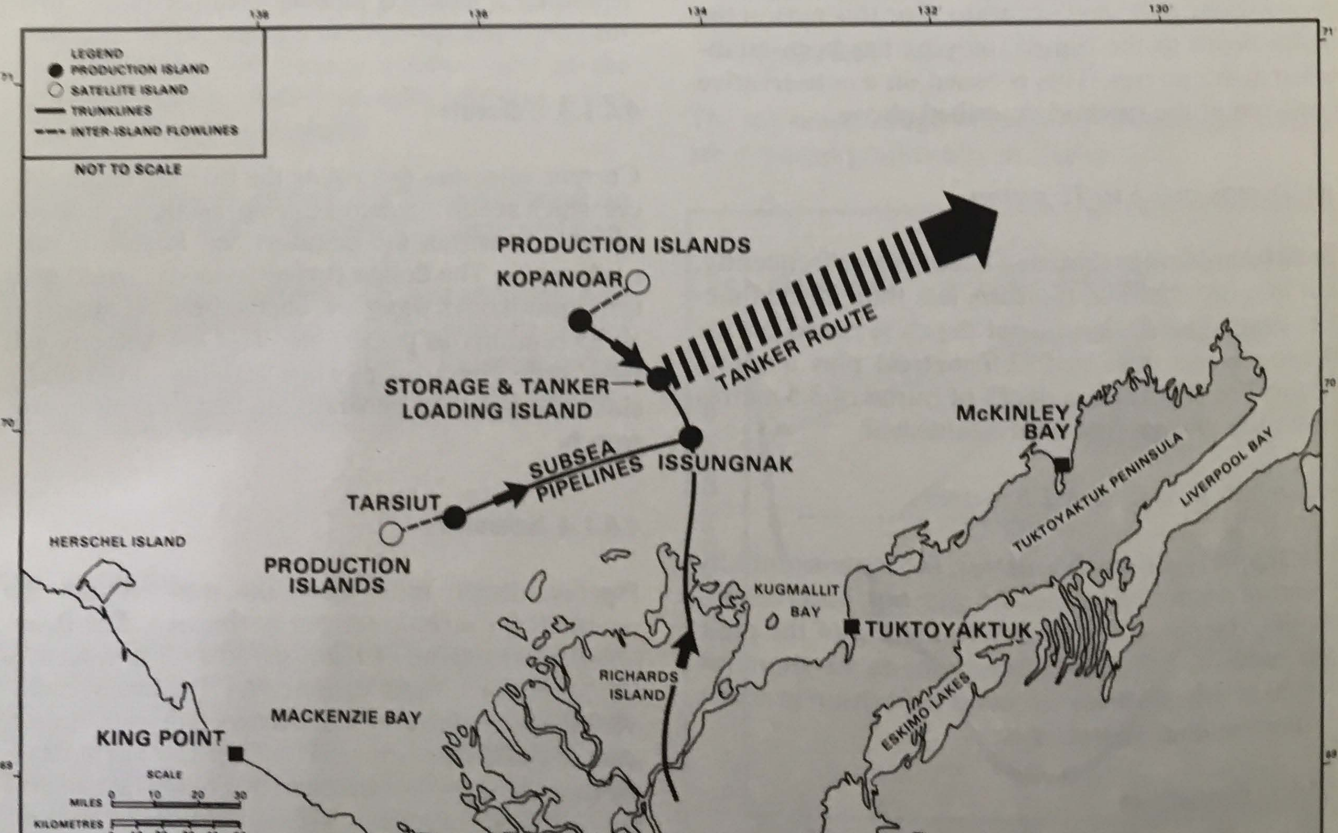

FIGURE 4.6-3 *The oil gathering subsea pipelines for the Arctic tanker option (Arctic oil tankers are used to transport oil to southern markets).*

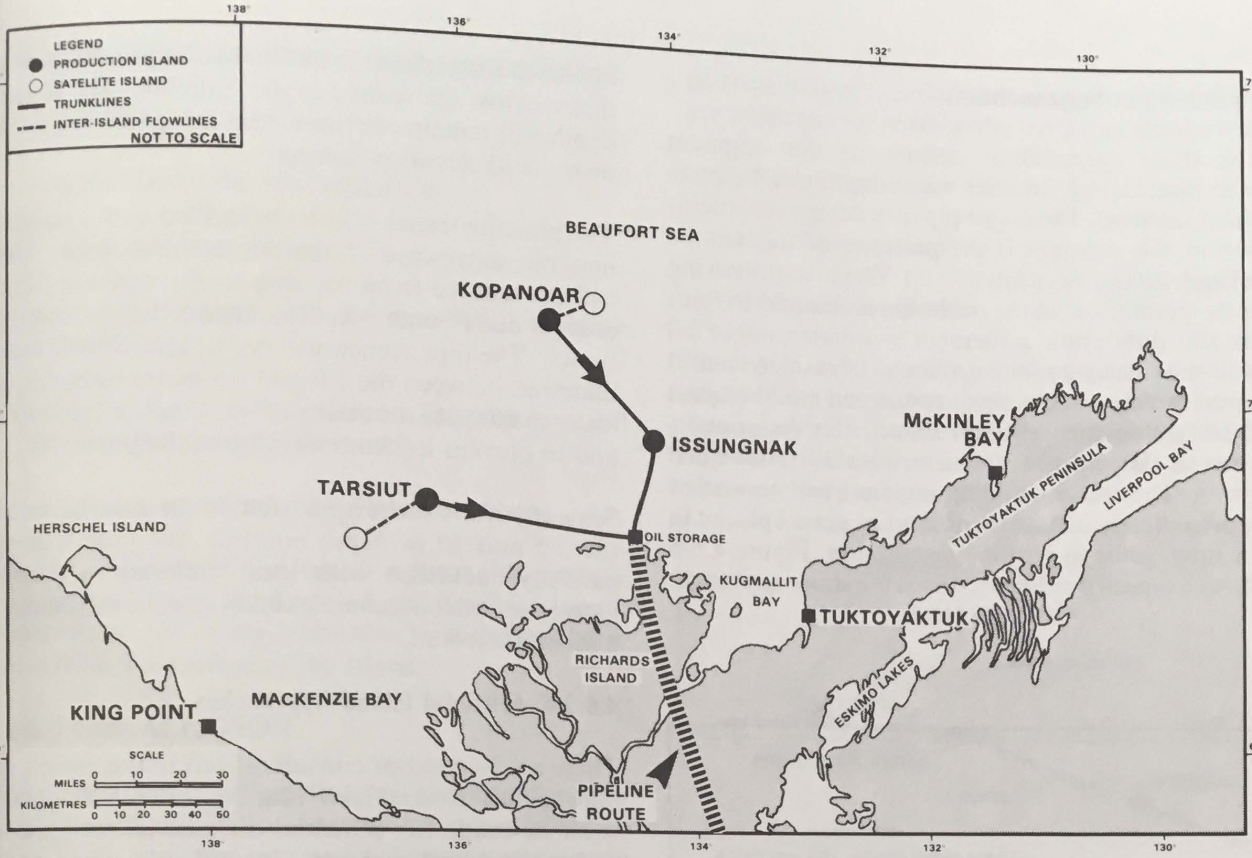

FIGURE 4.6-4 *The oil gathering subsea pipelines for the overland pipeline option.*

4.6.2.1 Trunkline Specifications

The range of specifications for the trunklines based on the above production rates are presented in Table 4.6-1.

4.6.2.2 Inter-Island Flowlines

Satellite islands connected to the Tarsiut central processing island (see Chapter 3) will require oil, gas and water injection lines, ranging in diameter from 168.3 millimetres to 323.8 millimetres.

Ice scour design criteria in this area dictate that the pipelines be trenched to a depth of 4.5 metres. To minimize trenching, these lines may be installed as bundles.

At Kopanoar, the inter-island flowlines will comprise a 508 millimetre crude oil submarine pipeline and a 355.6 millimetre gas pipeline. Both lines would be concrete coated to ensure that they do not float and would be trenched such that the tops of the lines are flush with the sea floor. No gathering system has been assumed at Issungnak. However, if additional islands are constructed, a system similar to Tarsiut would be installed.

TABLE 4.6-1

TRUNK-LINE SPECIFICATIONS

Parameter	Tarsiut to Taglu	Kopanoar to Issungnak	Issungnak to North Point
Diameter	508 mm (20 in)	762 mm (30 in)	762 mm (30 in)
Design Pressure	2470 kPa (355 psi)	4610 kPa (670 psi)	7310 kPa (1060 psi)
Wall Thickness	9.52 mm (.375 in)	15.88 mm (.625 in)	15.88 mm (.625 in)
Grade	CSA Z245.2-448	CSA Z245.2-448	CSA Z245.2-448
Submerged weight	38 kg/m (25 lb/ft)	45-95 kg/m (30-63 lb/ft)	45 kg/m (30 lb/ft)
Specific gravity	1.12	1.07	1.07
Design Throughput	20,000 m³/day (125 MBOPD)	80,000 m³/day (500 MBOPD)	95,000 m³/day (600 MBOPD)

4.6.2.3 Shore Approaches

The shore approach is defined as that segment extending from 2.5 metres water depth to 2.5 metres above sea level. The major pipeline design consideration in this segment is the presence of ice-bonded permafrost (see Section 4.6.1.2). To prevent thawing of the permafrost in the onshore section and to limit possible differential settlement to a maximum of 2.0 m in the offshore section, the use of insulation and gravel bedding is specified. Insulation could consist of 100 millimetres of foam installed in the annulus between the pipeline and a protective thin-walled casing. The trench bedding material will consist of approximately one metre of sand or gravel placed in the ditch prior to pipeline installation. Figure 4.6-5 shows a typical pipeline section at the shore approach.

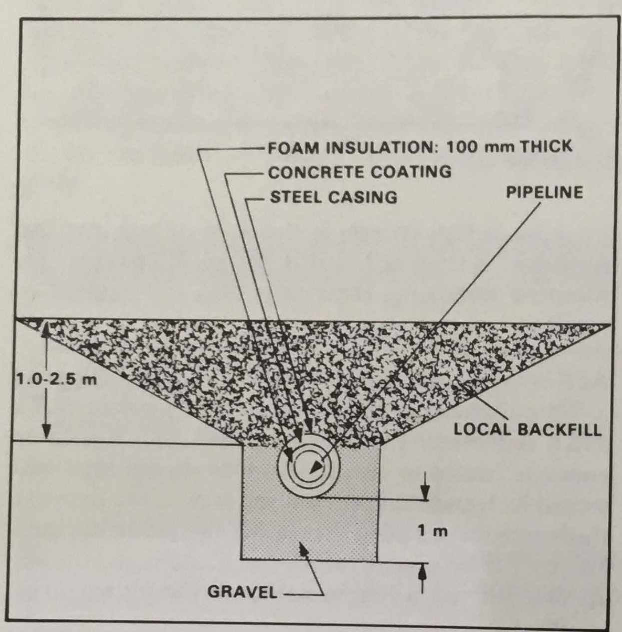

FIGURE 4.6-5 *A typical pipeline cross-section at a shore approach.*

The operating temperature of subsea trunklines may vary and will depend on the temperature of the crude oil as it leaves the production island. It is anticipated that the oil flowing in the pipelines will be cooled to a temperature of 13°C or less by the time it reaches the shore zone. The thickness of insulation required at the shore approaches may vary, depending on flow conditions, that could result in higher or lower temperatures.

Protection from ice scour and hydraulic erosion will be achieved by burying the pipeline 3.5 metres below the seabed at a water depth of 2.5 metres. Shoreward of this isobath the trench depth will decrease gradually until the pipeline is buried to a minimum of one metre below the seabed at the shoreline. The trench depth will remain constant from this point to the 2.5 metre land elevation contour.

The pipeline trench will be backfilled with granular material shoreward of the one metre isobath. This will prevent ice from freezing to the pipe and limit erosion due to under-ice flow channelling within the trench. The pipe trench will be backfilled with local material, between the 1.0 and 2.5 metre isobaths, in order to mitigate the action of wave induced scouring and to prevent ice from freezing to the pipe.

Seaward of the shore approach, in the zone between the 2.5 and 10 m depth contour, the pipe will be partially backfilled with local material to ensure long-term hydrodynamic stability and protect against hydraulic erosion.

4.6.2.4 Artificial Island Approaches

There are two major considerations in the design of approaches to artificial islands. First, allowance must be made for potential differential settlement within the island base area. Second, allowance must be made to protect the pipeline from ice contact. Several techniques which use proven technology are considered feasible.

One promising solution is to pre-install a horizontal casing on the seabed connecting to a junction box and a vertical shaft at the centre of the island. The shaft would be installed in stages during the island construction (see Figure 4.6-6). When completed the pipeline is pulled through the casing into the shaft and a riser connection is made in the junction box.

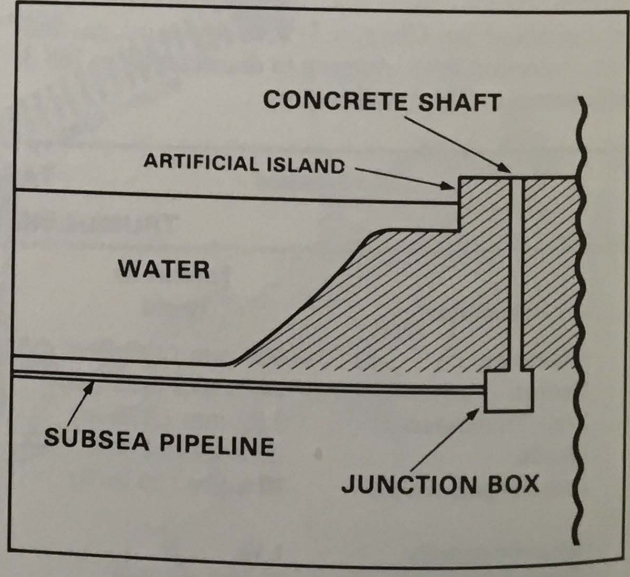

FIGURE 4.6-6 *During construction of an artificial island, a junction box, horizontal pipe casing and vertical connection shaft would be installed. The subsea pipeline would be pulled through the casing for connection in the junction box.*

There are several advantages to this proposed method:

- ease of repair;

- tolerance for thermal expansion;

- equipment availability;

- multiple casings can be installed for future expansion;

- tie end is completed within a junction box and permits future inspection; and

- low stresses induced by island settlement.

Other alternatives for island approaches include trenching within the berm of the artificial island, tunnelling, and casing placement by directional drilling from the surface of the island.

4.6.3 INSTALLATION

The installation of pipelines in the Beaufort Sea Region will require considerable advanced planning due to the remoteness, restricted open water season and Arctic conditions. Although the methods available for Arctic construction are based on standard world-wide practices, there will be a requirement for specialized equipment adapted for use in this environment.

To achieve the required trenching depth, a dredge such as a suction cutter dredge could be used shoreward of the 20 metre water depth contour, and trailing hopper dredges could be used in depths greater than 20 metres. The pipeline route will be dredged to produce a trench having a maximum depth and width at the sea floor of 5 and 22 metres, respectively. After installation of the pipeline, additional lowering, if necessary, will be achieved using smaller, specialized equipment such as a post-trenching plow, jetting or mechanical cutters.

The approximate volumes of excavated material for the trunklines described in the foregoing are:

Kopanoar to Issungnak
2.3 million cubic metres

Issungnak to shore
1.9 million cubic metres

Tarsiut to shore
2.6 million cubic metres

The installation methods for trunklines are determined largely on the basis of economics, low risk during installation and overall safety. Within the expected range of pipeline diameters, water depths and oceanographic conditions, three basic techniques are available for making the trunkline installations:

- pipe-laying barge;

- tow of pipe strings;

- ice-based installation.

The most widely used method of installation is the pipe-laying barge. Using the floating platform as a base, single or double lengths of pipe are welded together and then lowered safely to the seabed as shown conceptually in Figure 4.6-7.

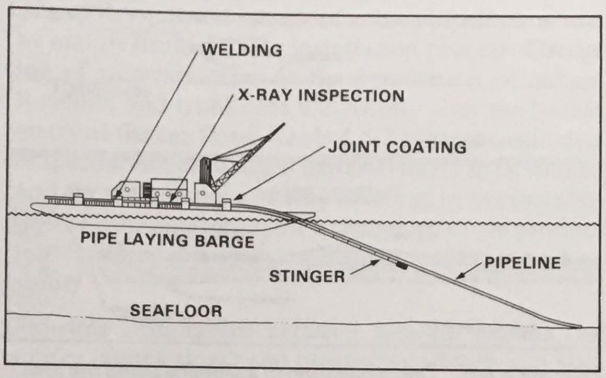

FIGURE 4.6-7 *The installation of a pipeline using a pipe-laying barge.*

There are over 50 pipe-laying barges in existence world-wide which would be capable of achieving lay rates of 0.75 to 1.25 kilometres per day. The major advantage of this equipment is that a continuous pipeline is laid and only one tie-in is required at its termination. Another advantage is that due to extensive usage, a broad base of expertise exists with several major pipeline contractors. The primary disadvantage is the high cost of the pipe-laying barge and attendant support vessels which would be required to complete this work during the short open water season. Such costs may justify the construction of a specialized lay barge built expressly for Arctic pipeline installation.

Another method for subsea pipeline installation suitable for the Arctic is the tow method. This method utilizes a land-based fabrication site to make sections of pipe several hundreds of metres long. These sections are welded together to form a pipe string which is towed offshore by a tug or a pull-barge during the summer, as shown in Figure 4.6-8.

Ice-based installation is another technique suitable for installing pipelines through bottom-fast or land-fast ice. This method consists of laying the pipeline through a trench cut in the ice as shown in Figure 4.6-9.

An advantage of the ice-based installation method is that conventional pipeline equipment may be used. However, this method is not suitable for installation seaward of the landfast ice boundary. This laying method would be most effective inside the one metre depth contour, where the ice is bottom-fast and a trench could be excavated immediately after a slot in the ice is cut.

As the inter-island flowline lengths are typically short, and the pipe size relatively small, the bottom tow method using tugs is considered practical for installing inter-island flowlines.

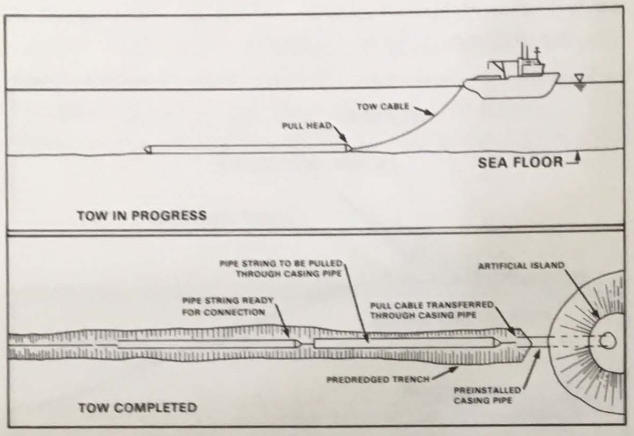

FIGURE 4.6-8 *The installation of a pipeline using the tow/-pull method.*

In addition to the methods described above, smaller diameter flowlines could be installed individually by reel ship or reel barge. This consists of a self-propelled vessel or barge capable of unspooling pipe to the sea floor at an approximate rate of 10 kilometres per day. The major advantage is speed of operation and minimization of tie-ins.

Two methods are applicable for the shore approaches:

- through-ice laying;

- bottom pull.

Through-ice laying has been described earlier.

The bottom pull method is a summer operation which utilizes a high capacity pulling winch to pull the pipe to shore as it is welded together on a pipe-laying barge positioned offshore. For this method, excavation of the trench is accomplished two summers prior to the pull to allow maximum thawing of exposed permafrost. A small suction cutter dredge may be used to excavate the trench. A welded connection will be made at a predetermined depth to join the segment installed through the ice in winter.

The installation method selected for artificial island approaches is to bottom tow a pipe string to a target

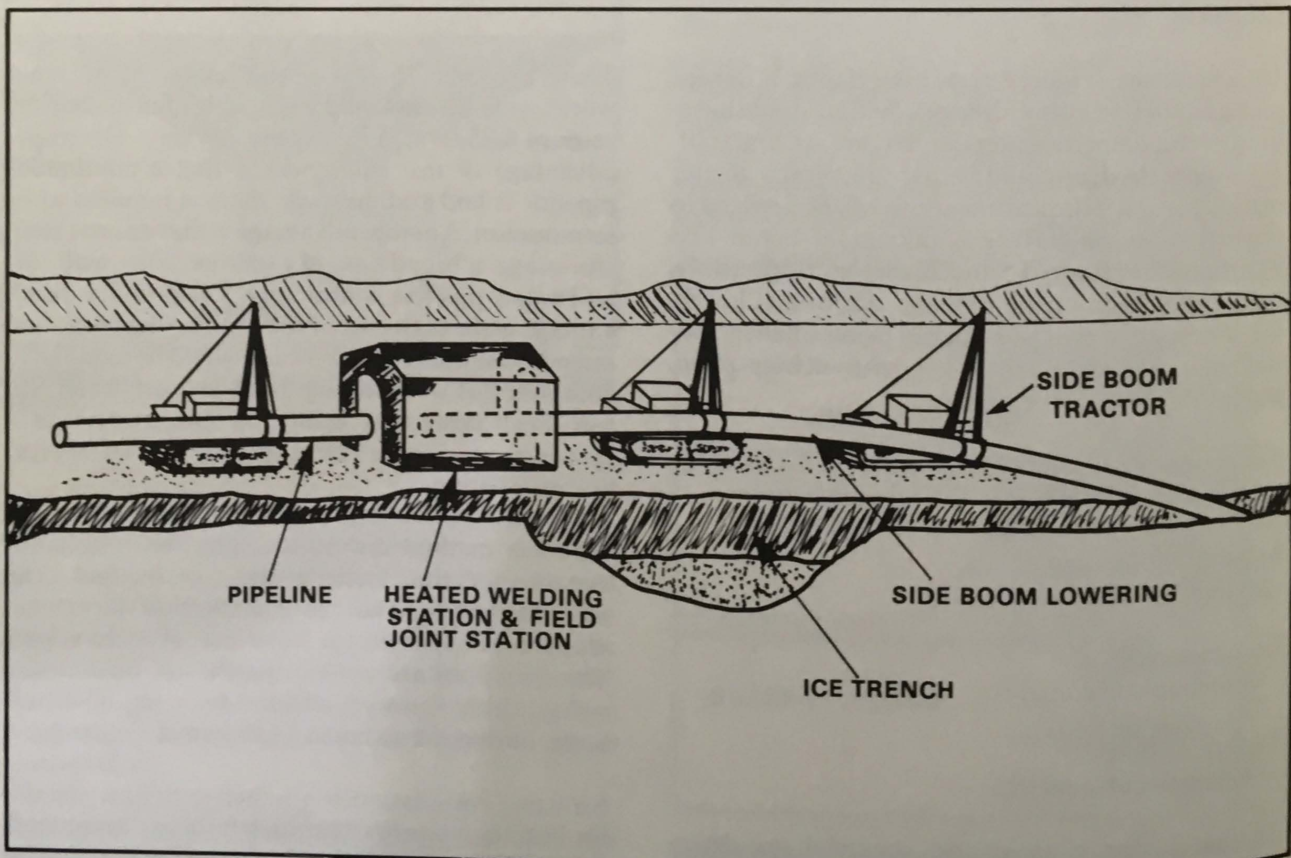

FIGURE 4.6-9 *Laying of a pipeline through a trench cut in the ice.*

position near the island and use an island based winch to pull the string into a pre-installed casing.

Based on the foregoing example, it is estimated that the major pipeline installation activities could take up to six years to complete. Approximately 100 people would be required during the first year, peaking to approximately 2,400 at the busiest period of construction.

4.6.4 OPERATIONS

An operating plan will be implemented utilizing state-of-the-art equipment in key areas of operation. Operations, including control, monitoring, and maintenance of the subsea pipeline network will be carried out from a central base, which could be located at an onshore overland pipeline terminal, or at the offshore tanker storage terminal. Direct communication from either of these locations will be continuously maintained with the processing islands, and all oil movements throughout the network will be automatically scanned and monitored by computer.

Several methods exist for monitoring pipeline throughput for possible leaks, a number of which could be implemented to provide comprehensive detection capability. The first is the mass flow comparison technique, which uses computer analysis to adjust input and output flow rate meters for variations in temperature and density. Shutdown can be manual or programmed to occur at a pre-set threshold of variance between readings. The accuracy of these systems is approaching 0.25 to 0.5% of flow. The second method involves the simple comparison of net flow readings at each end of the pipeline. If successive readings indicate a trend, progressive shutdown procedures are initiated. Although this method does not provide instantaneous leak recognition, it is applicable for loss rates less than 0.5% of flow. A third method is acoustic monitoring for pressure waves which may indicate rapid loss of oil. This method would be used primarily as a backup system.

4.6.5 PIPELINE REPAIR

Should pipeline repair become necessary, numerous offshore pipeline repair methods have been developed and specialized repair equipment is in existence. These methods consist of either surface or seabed repairs.

With the exception of pipelines under thick ice in a water depth greater than 20 metres, most repairs, if required, could be completed in 30 to 40 days. Repairs in water depths greater than 20 metres could take longer and may require icebreaker support to create an area of broken ice which can accommodate a specialized repair vessel. Repairs could be accomplished by cutting the pipeline, dewatering each segment and raising the ends to the surface. The use of auxiliary buoys would be required in depths greater than 40 metres. Alternatively, repairs can be made using divers to install pipeline connection devices or to make welds.

It is anticipated that approximately 80 persons will be required for routine pipeline operations.

4.6.6 POTENTIAL ENVIRONMENTAL DISTURBANCES

This section identifies likely and potential environmental disturbances from subsea pipelines. Environmental impact is examined in detail in Volume 4.

The environmental impact of subsea pipelines would be mainly limited to the installation process. Dredging of trenches prior to the installation of subsea flowlines and trunklines will locally alter the bathymetry of the sea floor. Table 4.6-2 presents estimates of the amount of dredged material likely to be moved and the area of right of way involved in the installation of trunklines from the example offshore production facilities at Kopanoar, Tarsiut and Issungnak to shore.

Flowline installation between satellite islands (or subsea completions) and processing islands will also involve dredging. For example, seafloor disturbance at Kopanoar may amount to 10 ha and at Tarsiut, 92 ha.

Due to the measures required in the shore approach zone to deal with permafrost and to protect the pipeline from ice, the sea floor and an area of land onshore will be disturbed by the pipeline right-of-way and through the excavation of granular material. It is estimated that 2.5 ha of sea floor and 3 ha of land area will be disturbed by the shore approach of a subsea pipeline.

TABLE 4.6-2
ESTIMATE OF DISTURBED AREA OF SEA FLOOR

	Kopanoar to Issungnak	Issungnak to Shore	Tarsiut to Shore
Length (km)	51	45	73
Dredged Volume (m^3)	2.3×10^6	1.9×10^6	2.6×10^6
Affected Right of Way (ha)	216	165	260

4.7 ONSHORE GATHERING SYSTEMS

Crude oil has been discovered at nearshore and onshore locations in the Mackenzie Delta and Tuktoyaktuk Peninsula, specifically at Adgo, Garry, Kumak, Kugpik, Ivik and Atkinson. The extent of these discoveries is relatively small compared to offshore discoveries in the Beaufort Sea; however, the

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known oil reserves are estimated at 32 million cubic metres. The production rate of these reserves could approach 8,000 cubic metres per day.

Oil produced from these reserves would likely be transported by gathering systems to a large diameter overland pipeline. Figure 4.7-1 shows one of the many pipeline gathering system configurations that might be considered for onshore and nearshore oil transmission.

Alternatively, if produced oil from the Beaufort Sea-Mackenzie Delta were transported to market by Arctic tankers, onshore and nearshore production would be delivered via onshore gathering systems to a site such as North Point for transmission to the offshore tanker loading terminal by subsea pipeline. Figure 4.7-2 shows one option of gathering systems for tanker transportation.

Crude oil from onshore and nearshore discoveries found to date can be pumped near ambient ground temperature. For this reason, the gathering system will be installed in the buried mode, without the threat of permafrost degradation. Due to the relatively low rate of production from each of the fields, small diameter pipelines ranging from 219 millimetres to 508 millimetres can be used.

Based on the location of existing discoveries, it is estimated that approximately 300 kilometres of small diameter buried pipelines would be required for the onshore oil gathering system. As additional onshore and nearshore discoveries will likely be made in the Region, every attempt will be made to design the gathering system so that future discoveries can be connected via the shortest possible route.

Major gas reserves have also been found in the Delta, at Niglintgak, Parsons Lake and Taglu. An overland gas pipeline, built to transport gas to southern markets (see Section 6.2) would pass close to these fields, minimizing the need for gas gathering. However, if new commercial gas discoveries are found in the Delta, gas gathering pipelines may need to be built. Gas associated with oil production will also be transported to the main gas transmission system.

4.7.1 DESIGN CONSIDERATIONS

The following will briefly describe the environmental design considerations for onshore gathering systems. More information on the nature of the physical environment of this region is provided in Volumes 3A and 3C.

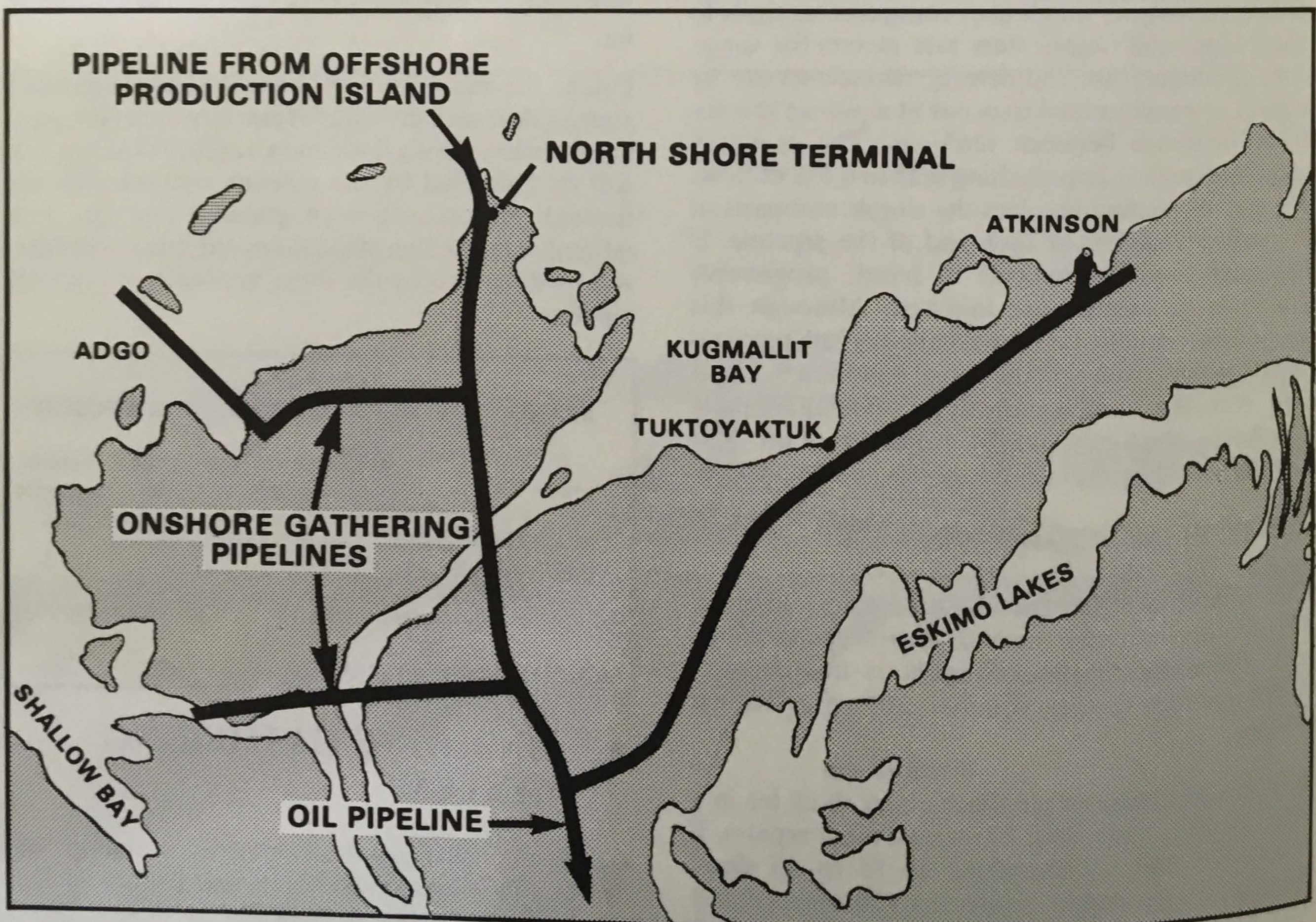

FIGURE 4.7-1 *An onshore system for the gathering and transportation of crude oil to the proposed large diameter overland pipeline.*

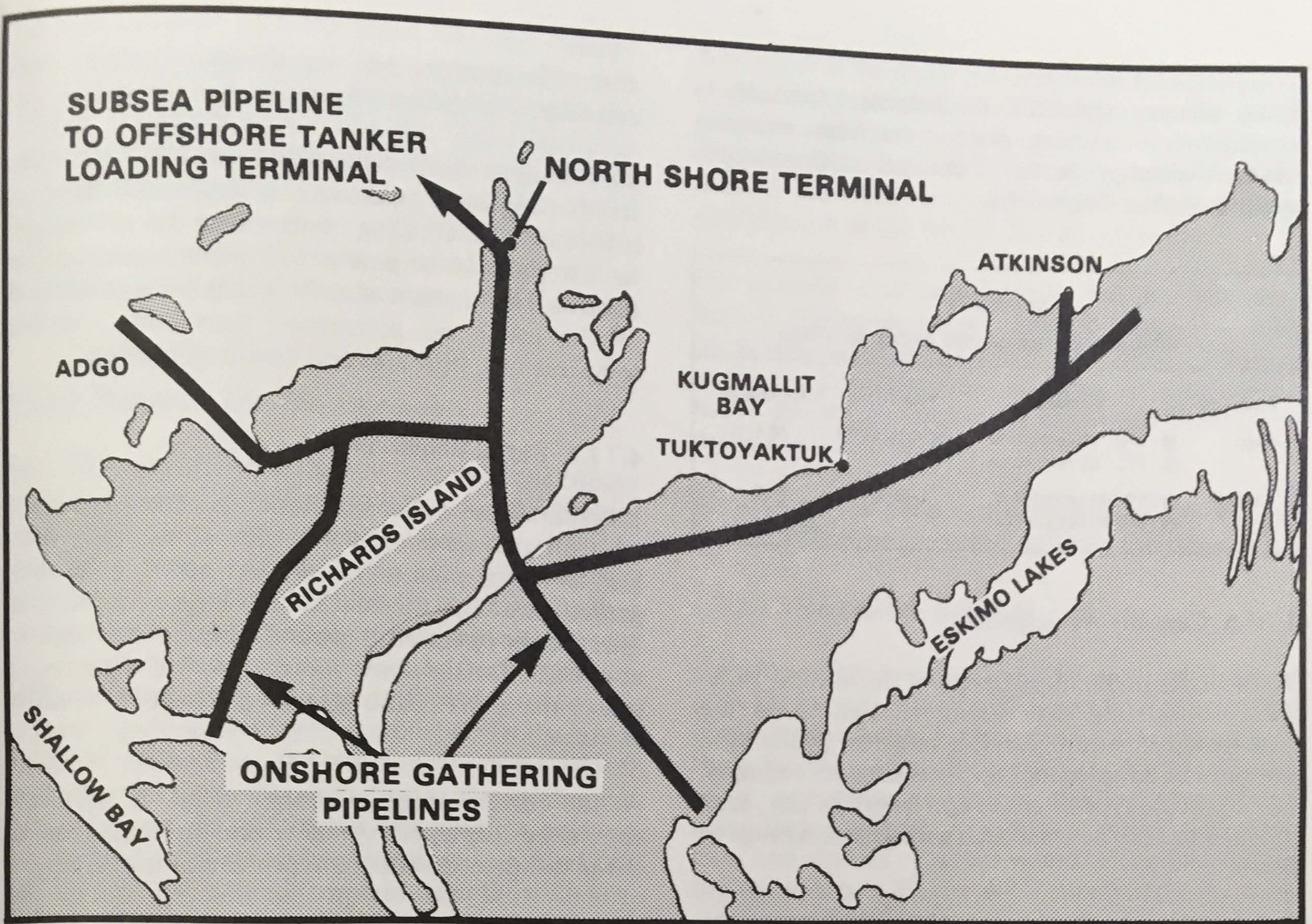

FIGURE 4.7-2 *The anticipated system for transporting crude oil from onshore oil reserves to the North Point Terminal, before proceeding offshore into tankers.*

4.7.1.1 Terrain and Surficial Soils

The terrain of the Mackenzie Delta shows little relief; elevations range from sea level along the northern, seaward edge to a maximum of 5 metres above sea level, and slopes are less than 10 degrees. Channels and small lakes are abundant. The surficial soils are fine grained and are ice-rich, with visible ice contents ranging from 5 to 50% by volume.

The topography of Richards Island and the Tuktoyaktuk Peninsula is level to undulating with a hummocky surface. Elevations range from sea level along the coast to greater than 100 metres on Richards Island. Typical terrain elevations, however, range up to 30 metres above sea level. Slopes of 5 to 10° are characteristic. Silts and sands are the most widespread surficial deposits. Visible ice content ranges from less than 5% by volume in the coarser outwash deposits to 75% in the fine grained sands and silts.

4.7.1.2 Soil Temperatures

The Mackenzie Delta and the Tuktoyaktuk Peninsula are located in the continuous permafrost zone of Canada. Consequently, the soil temperatures are on average at or below freezing temperatures. The soil temperatures at a depth of one metre average about -12.2°C during the winter and -1.7°C during the summer. In areas where there is less vegetation and organic soil at the surface, the temperatures could be slightly lower in the winter and slightly higher in the summer.

4.7.1.3 Route Selection

A buried oil pipeline located in the continuous permafrost and operated near ambient ground temperature would have little impact on the environment, and allows for some degree of flexibility in selection of specific routes. The exact routes of the gathering systems and production rates of the oil fields that will be served by the system have not yet been established. It has been concluded, however, that locating pipelines in the Mackenzie Delta and Tuktoyaktuk Peninsula is technically feasible.

4.7.1.4 Typical Oil Properties

Crude oil discoveries to date indicate that two types of crude oil exist in the general area. Crude oil from the Adgo discovery represents a low API gravity oil that has a relatively high viscosity at low tempera-

tures, whereas crude from the Atkinson discovery is considered a medium gravity, medium viscosity crude. Typical properties of the two crude oil types are provided in Table 4.7-1.

TABLE 4.7-1

CRITICAL PROPERTIES OF TWO CRUDE OIL TYPES

Discovery	Viscosity	Pour Point	A.P.I. Gravity
Adgo	@ 0°C-170 centistokes @ 15°C- 65 centistokes	-46°C to -57°C	18.4
Atkinson	@ 0°C-134 centistokes @ 15°C-61 centistokes	-48°C	24.0

4.7.1.5 Capacity Assumptions

To facilitate preliminary design of the onshore pipelines, considering that additional discoveries are anticipated in future years, a range of production rates can be adopted and the lines sized accordingly. For a specific type of crude and length of line, each pipeline size can be associated with a certain range of flows.

The flows considered were 65, 200, 400 and 660 cubic metres per hour and the lengths analyzed were 80 and 160 kilometres. Pipe sizes were generated for the two types of crude oil by hydraulic and thermal analyses.

During the final design stage, using known crude properties and a site specific route, more detailed hydraulic, thermal, geothermal and geotechnical analysis may indicate that an uninsulated, buried gathering system is feasible. For the purpose of this preliminary analysis a conservative approach, which assumes a completely insulated buried pipeline system, has been taken.

The preliminary criteria used in the analysis are summarized below:

1. The pressure drop in the line should not exceed 9,650 kPa, thereby eliminating the requirement for intermediate booster pump stations.

2. The temperature of the oil in the line should not drop below -5°C. This was selected as the conservative limit for which the properties of the crude oil could be confidently extrapolated. This limit was also considered important to permit transport of more viscous types of oil should such be discovered.

3. The temperature of the oil in the line should not exceed 0°C, to ensure that the line does not thaw the surrounding permafrost.

The minimum diameter line with a minimum thickness of insulation, that met the above criteria, was considered as the optimum size.

This analysis demonstrated the need to ensure that the flowing oil temperature is maintained between 0°C and -5°C. Chilling of the oil at the production facility prior to shipment will achieve temperature control. The amount of chilling required is a function of the crude oil properties, flow rate, ambient temperatures, pipe size and length of pipeline.

4.7.1.6 Burial Requirements

Initial analyses indicated that all pipelines provided with thermal insulation will prevent excessive heat loss from the pipe in the winter; however, further geotechnical and thermal studies have revealed that lines may be operated at ground temperatures slightly above 0°C for the short summer period. This could reduce the need for insulation over a major portion of the system.

At the current stage of design detail, it has been concluded that approximately one metre of ground cover will provide adequate protection to the pipe.

4.7.1.7 River and Channel Crossings

The gathering systems will cross streams, rivers or channels of the Mackenzie River.A considerable amount of information is available on the main distributing channels in the Mackenzie Delta from extensive studies carried out in the area for other projects, e.g. Canadian Arctic Gas Pipeline. As a result of these studies, it is concluded that all crossings could be constructed in a buried mode.

Most of the rivers and channel bottoms in the region under consideration remain unfrozen throughout the year. The pipeline will thus be provided with a moisture resistant type of thermal insulation and outer wrap to prevent the freezing of river bottom material and potential frost-heave. The pipeline will also be coated with reinforced concrete to counteract buoyancy.

Depth of burial for the pipe within the river channel will be at sufficient depth to be safe from structural damage resulting from scour. Pipe burial will extend into the river banks and channels to ensure that pipe does not become exposed due to bank erosion. The location of all river crossings will not be decided until site specific field evaluations have been completed.

4.7.1.8 Valve Spacing

The gathering system will be located in remote areas with limited accessibility, especially in the summer months. Isolating valves will be provided on the sys-

tem in accordance with the latest National Energy Board Pipeline Regulations. The isolating valves will limit the amount of oil lost from the pipeline in the unlikely event of damage to the line. Isolating valves will be located on both sides of major river or channel crossings. They are also required to isolate sections of the pipeline for maintenance purposes. These valves will be provided with remote control devices connected through a communication system to a control centre.

4.7.1.9 Nearshore Pipeline Approaches

For fields located in the shallow waters of the Mackenzie Delta and southern Beaufort Sea, subsea pipelines will connect with the nearest onshore gathering line. While the line sizes will be relatively small compared to the pipelines carrying oil from production facilities located in deeper water, similar environmental design criteria and construction techniques, as outlined in Section 4.6, will be applicable. In addition to the design considerations established for the larger diameter subsea lines, the temperature of the oil will be controlled by artificial cooling at the production islands so that the differential temperature, between the flowing oil as it reaches the buried onshore line and the ambient ground temperature at the shoreline, will be minimized.

4.7.2 CONSTRUCTION

4.7.2.1 Construction Techniques

All onshore portions of the gathering system will be constructed during winter, whereas the crossings of the Mackenzie River channels will be constructed during the summer. Arctic pipeline construction techniques are described in detail in Section 6.2 and this section summarizes the significant construction aspects applicable to the gathering system.

The gathering system will be constructed on a right-of-way 20 metres wide. The area over the trench will be cleared of vegetation prior to the start of construction activities. The centreline of the pipeline will be located off the centreline of the right-of-way. The wider portion of the right-of-way will be designated as the 'work area' while the narrower portion will be the 'spoil area.' Snow will be used to prepare the work area rather than the conventional cut and fill method of grading. Construction of snow roads for the work area of the right of way in winter has been recognized as a technique causing limited environmental impact while providing a good quality travel and work area. Where additional snow is required, it will be collected by means of snow fences or mined from large drifts in the area and trucked to location.

A trencher is the preferred equipment for excavation of ditches in permafrost. Trenchers provide good progress and cut a smooth and even ditch bottom. The spoil from the trencher is well suited as backfill material. In areas containing large boulders, drilling and blasting of the trench may be required.

For summer installation of river and channel crossings, a dredge or barge mounted backhoe would likely be used for excavation of the trenches. Alternatively, these crossings may be traversed using a technique known as horizontal controlled directional drilling, where feasible.

Sections of the proposed gathering system will be individually pressure tested to verify their integrity.

4.7.2.2 Construction Schedule

Approximately two years will be required to complete the necessary field studies and final engineering design for the Adgo, Atkinson and Kumak laterals of the gathering system. The construction of the system, using one construction spread, could take two winter construction seasons. As indicated earlier, the major river and channel crossings would be completed during the summer. Figure 4.7-3 summarizes the construction schedule.

4.7.2.3 Construction Resources

During the year prior to construction of the gathering system, a preconstruction crew of some 50 personnel would be required to prepare camp sites, temporary wharves and roadways. During the two winter construction seasons, approximately 300 personnel would be required to construct the system. A labour force of 70 people would be required for the summer construction of the river and channel crossings.

Materials, fuel, and equipment would be transported by barge from Hay River to stockpile sites in the Mackenzie Delta and Tuktoyaktuk Peninsula. Winter snow roads would be used to move the construction materials and supplies to the pipeline right-of-way.

4.7.3 OPERATION

The gathering system would be operated and controlled from a control centre equipped with a supervisory and control system (SCADA). The SCADA system consists of remote terminal units in the field where measurements are taken and flow control devices located. Information will be relayed to the master terminal unit at the control centre. The computer assisted master terminal unit provides a means for collection and display of operational conditions and for control of the system by action of the system operator.

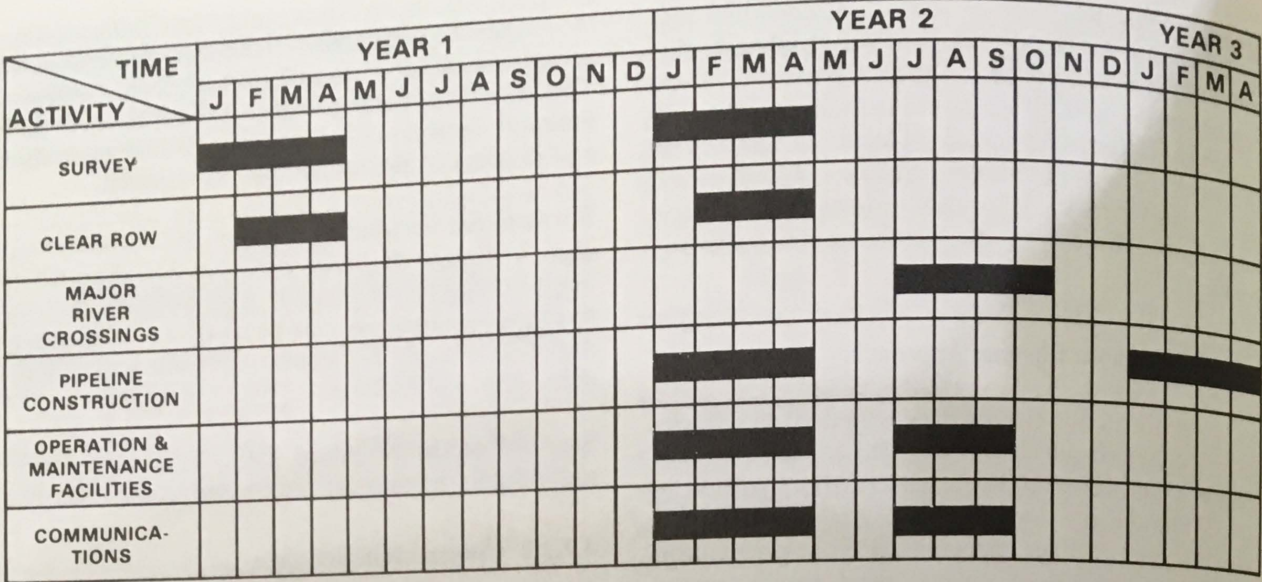

FIGURE 4.7-3 *Construction schedule for an onshore gathering system.*

Oil entering and leaving the gathering system will be continuously monitored, providing the operator with the capability of detecting leaks in the system.

The location of the operations and maintenance bases for maintenance personnel and equipment will depend on the final configuration of the system. The preferred locations for these bases will be at the production facilities or at the terminal.

4.7.4 ABANDONMENT

In the event that at some future time it may be desirable to remove the pipeline or some portion thereof from service, an application will be made to the regulating authority for approval to deactivate the facilities.

Procedures adopted at the time of abandonment would include:

- removal of all oil from the pipelines;

- removal of those sections of pipe from locations where it could interfere with future land development; and

- removal and salvage of surface facilities.

4.7.5 POTENTIAL ENVIRONMENTAL DISTURBANCES

This section identifies potential environmental disturbances associated with onshore gathering systems. Volume 4 examines environmental impact in detail.

Since no intermediate pumping stations are anticipated within the onshore gathering systems, environmental disturbances are limited to construction related activities. It will be necessary to remove the vegetative cover over the pipeline ditch, however, this material will be segregated from the trench spoil and returned to its position over the covered pipeline.

The impact of buried pipelines in this region where trees and shrubs are sparce will be minimal. With the use of proven construction techniques, river bank erosion concerns should not be a problem. Some areas of land will be affected by the location of construction camps, docks and material stockpiles. The environmental impacts associated with construction camps are described in Section 5.3.

Access to the different points of the system will be based mainly on the use of the right-of-way during winter and via air travel. Low ground pressure vehicles will also be used for emergency access to the line in the summer time.

Dredging activities would be cause for localized concerns respecting the fisheries resource and water quality.

Timing and siting of river crossing construction will be planned so that disturbance to the fisheries resource and waterfowl is kept to an absolute minimum.

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CHAPTER 5

BEAUFORT SEA-MACKENZIE DELTA SUPPORT SYSTEMS

One might define a support system as any system which is external to the sites where exploration or production operations take place but that is required to facilitate those operations. Support systems thus include basic physical infrastructure such as airports, roads, housing, power and communication systems, and also the personnel and organizations necessary to construct and operate them.

Conventional land-based oil exploration and producing operations in southern Canada look to the local community and oil service industry for support systems. In these areas, support services grow along with the industry. In northern Canada, support systems play a crucial role in exploration and production operations because of the remoteness of the area and the lack of existing services. These services in the Beaufort Sea-Mackenzie Delta Region will be expanded in the coming years, and will have a considerable impact on some of the existing communities. Offshore activities in the Region have necessitated a significant complement of marine vessels. Support systems are discussed in this section under three basic categories - marine support systems, air support systems, and land support systems.

5.1 MARINE SUPPORT SYSTEMS

Exploration, construction and production activities in the Beaufort Sea-Mackenzie Delta Region require an extensive marine support system. A large part of this fleet is comprised of supply ships used to transport supplies from main support bases to offshore facilities. This fleet also includes seismic vessels, dredges used to build artificial islands, the icebreakers that make these operations possible, and a variety of barges and other vessels. These vessels must be specially designed or adapted to operate in Arctic conditions. In the future new vessels specifically designed for Beaufort Sea operations, such as Arctic class dredges, will be added to the marine support system.

5.1.1 SUPPLY BOATS

Storage space on drillships and artificial islands is limited. While islands can store consumables for a complete well, drillships cannot and, therefore, resupply is required several times during the drilling of a well. Supply boats carry cargo from the shorebase, where a large inventory is stored, to the offshore sites. The cargo is offloaded at the drillship or island and excess material or refuse is brought back to the shorebase.

An average supply boat carries 700 to 1,000 tonnes of cargo. They have a large, clear afterdeck to facilitate loading and unloading of tubulars and palletized materials. They are also equipped with pressurized storage systems for carrying powdered bulk material (cement and barite) and have a large fuel carrying capacity. Material supply operations will be managed by a computerized planning and scheduling system so that inventories can be minimized and maximum use can be obtained from supply boats and other facilities. The number and type of vessels projected to be used in this region up to the year 2000 are discussed in Chapter 3 of this volume.

Plate 5.1-1 is a photograph of a supply vessel operating in the Beaufort Sea. Plate 5.1-2 shows the SUPPLIER 7 which is fairly typical of standard offshore supply vessels. Plate 5.1-3 shows the CANMAR SUPPLIER 8. It is a specialty shallow draft supply vessel 60 metres long, having about twice the cargo capacity of the other vessels. It also has a Class 2 icebreaking capacity.

New generation drillships, production islands and APLAs will have different supply requirements than present drillships and islands. In the case of the extended season drillships and year-round islands, these will have a storage capacity two or three times larger than that of the present drillships, and an almost unlimited storage capacity in the case of APLAs. These year-round operations will necessitate the use of supply vessels which will also be able to operate year-round in the Beaufort Sea. Larger vessels will be required because of the large storage capacity at the receiving end. However, production operations require a much lower level of resupply than drilling operations since there are few consumables involved. Thus, once drilling has been completed from a production island or an APLA, the supply boat requirements will be reduced. Figure 5.1-1 is an illustration of the CANMAR SUPPLIER 9, now named the ROBERT LEMEUR, which will be operating in the Beaufort in the 1982 season. This Class 3 icebreaker/supply boat will have the capability to provide supply service over an expanded season (June to December) and will have a large cargo carrying capacity.

ulf is currently building two Class 4 supply vessels, named the MISCAROO and the IKALUK, which will go into service in 1983. The specifics of these vessels and their general appearances are provided in Figure 5.1-2.

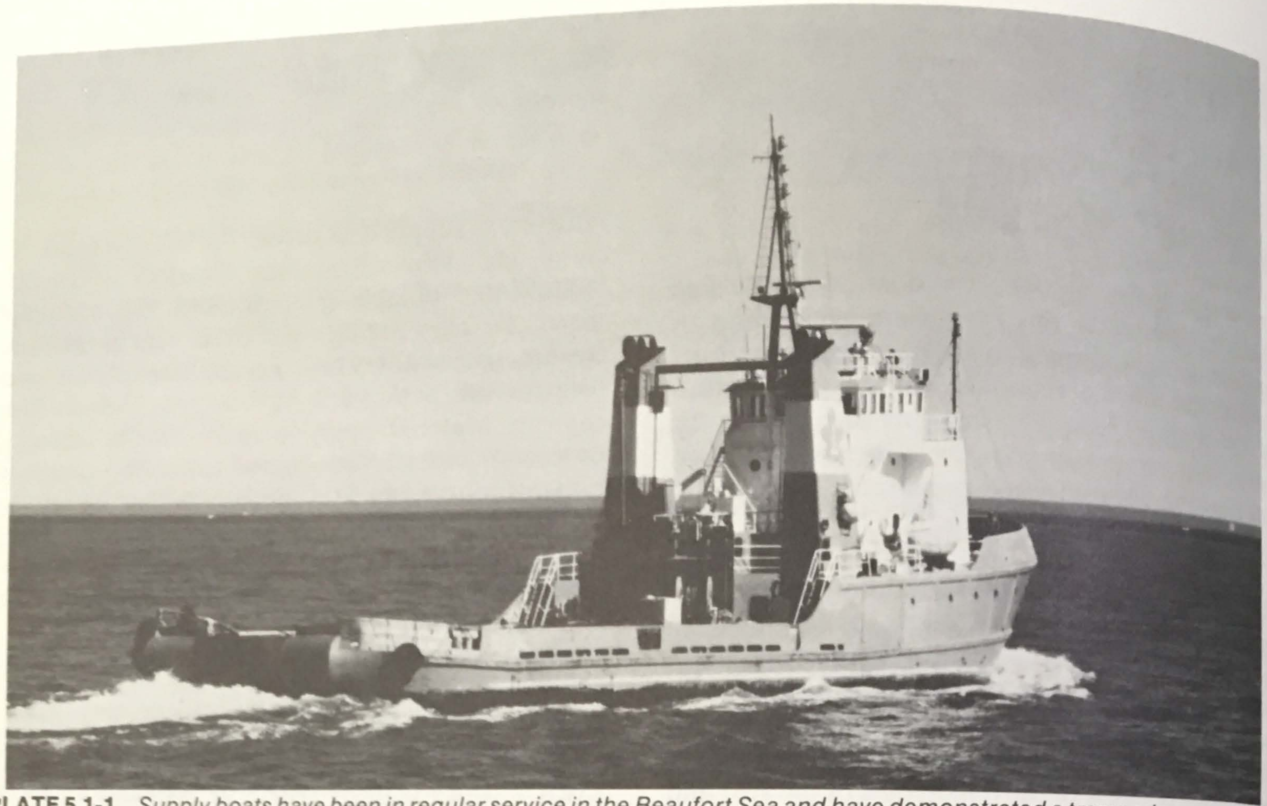


PLATE 5.1-1 *Supply boats have been in regular service in the Beaufort Sea and have demonstrated a tremendous capability to work in first-year ice.*

PLATE 5.1-2 *The SUPPLIER 7, a typical offshore supply vessel, transports cargo between Tuktoyaktuk and McKinley Bay and the drillships.*

PLATE 5.1-3 *The CANMAR SUPPLIER 8 is a specialty, shallow draft supply vessel, 60 metres long, used for supplying casing, drilling mud, cement and other consumables to the drillships.*

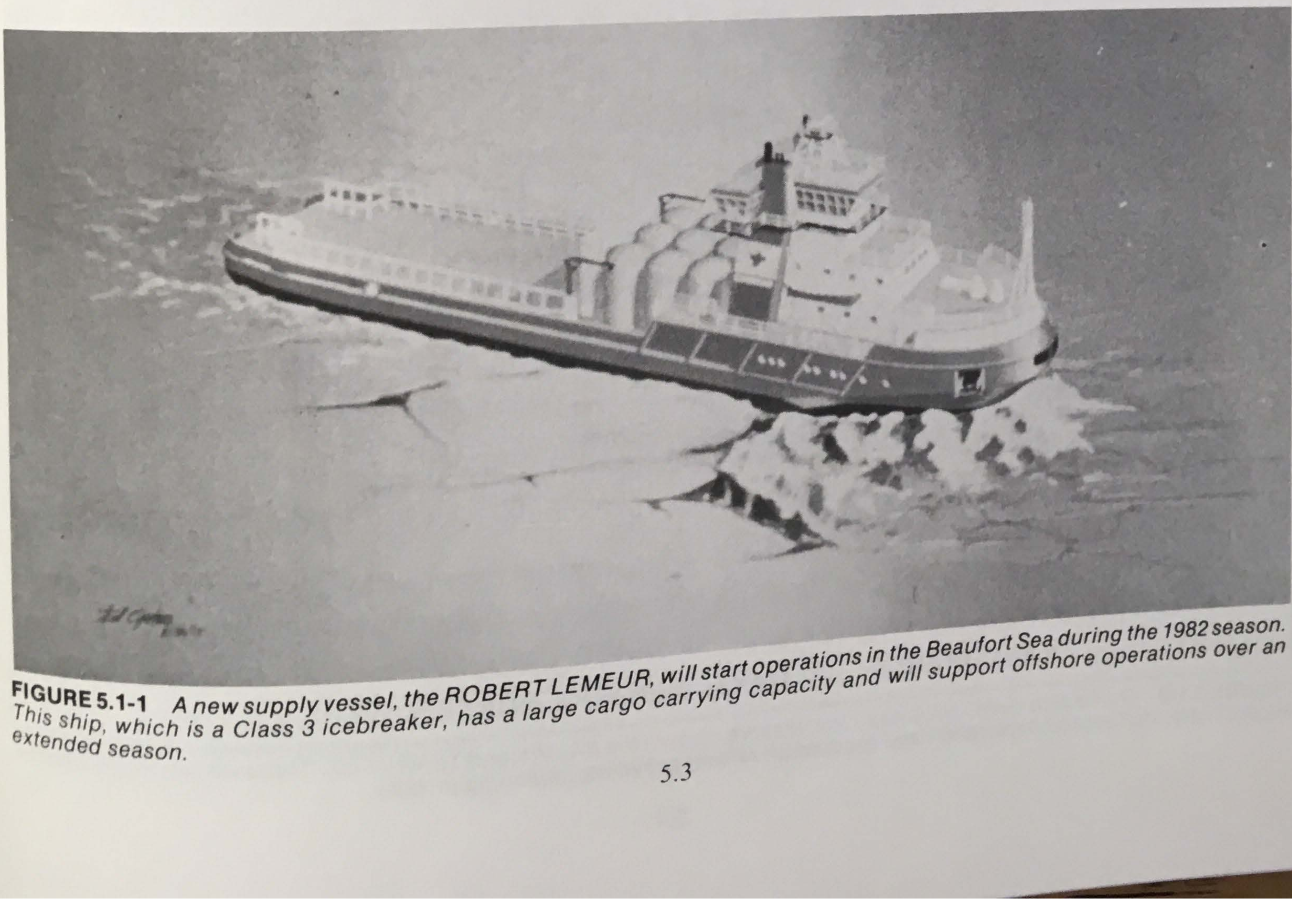
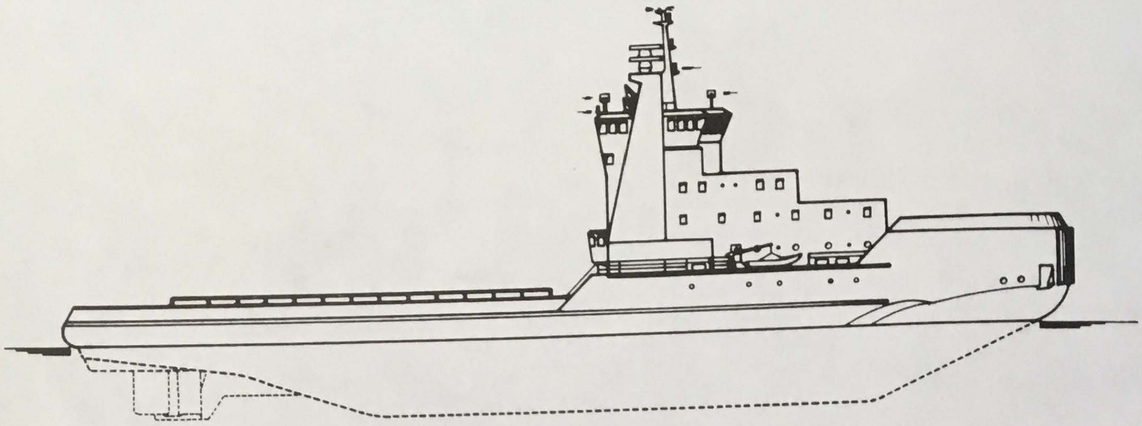


FIGURE 5.1-1 *A new supply vessel, the ROBERT LEMEUR, will start operations in the Beaufort Sea during the 1982 season. This ship, which is a Class 3 icebreaker, has a large cargo carrying capacity and will support offshore operations over an extended season.*

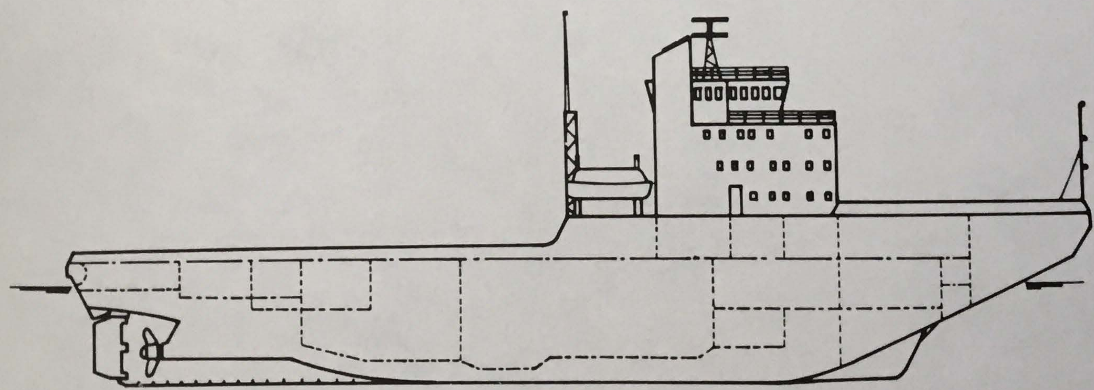
SUPPLY VESSEL/ICE CLASS IV



- LENGTH OVERALL 79m
- DESIGN DRAFT 7.5m
- POWER 4x3,500 Bhp/TWIN SCREW
- FULL LOAD DISPLACEMENT 5,000 TONNES
- CARGO CAPACITY 1,400 TONNES
- UNOBSTRUCTED DECK AREA 41m x 11m

FIGURE 5.1-2 *Gulf is currently building two Class 4 supply vessels in Vancouver, named the MISCAROO and the IKALUK, which will go into service in 1983.*

ICEBREAKER/ICE MANAGEMENT VESSEL



PARTICULARS

- LENGTH OVERALL 88.0m
- DESIGN DRAFT 8.0m
- INSTALLED HORSEPOWER 24,000
- LIGHTSHIP DISPLACEMENT 4,400 TONNES
- FULL LOAD DISPLACEMENT 6,800 TONNES
- CARGO CAPACITY 800 TONNES
- ENDURANCE 20 DAYS (60% FULL HORSEPOWER)

FIGURE 5.1-3 *Gulf is also building 2 Class 4 icebreakers, named the KALVIK and TERRY FOX. These vessels will be used to support extended season exploration and production related activities, beginning in 1983.*

5.1.2 ICEBREAKERS

The need for icebreaking service to assist oil industry operations is unique to the Arctic. There are several types of icebreaking services required, some in the present exploratory operation and some in the future year-round exploratory and producing operations. Some of the supply boats currently operating in the Beaufort Sea have icebreaking capacity, but this section deals with those ships which have been specially designed to function as icebreakers, though they may also function as supply or standby vessels.

Research has been carried out for some years on the design of icebreaking vessels for Beaufort Sea operations. The CANMAR KIGORIAK, which was brought into the Region in 1979, was the first vessel to be purpose-built incorporating special design features. The KIGORIAK, shown in Plate 5.1-4, is a Class 3 icebreaker which has been used both to assist drillships and for research purposes. Testing of the KIGORIAK has demonstrated successful year-round icebreaking performance and information gathered has been used in subsequent designs.

One special design feature of the KIGORIAK is the reamer, shown in Plate 5.1-5, which cuts a channel through the ice 2 metres wider than the hull, thereby both reducing friction and increasing manoeuvrability. A water spray system in the bow area (Plate 5.1-6) also reduces friction by providing a lubricating layer a few centimetres thick between the hull of the ship and the ice. Other design improvements incorporated into the ship include the bow shape, a stern design and protective nozzle to keep ice away from the propeller, and a friction reducing hull coating which will also limit hull corrosion.

Gulf is presently building 2 Class 4 icebreakers named the KALVIK and TERRY FOX in Vancouver (Figure 5.1-3). These vessels will be used to support extended season exploration and production related activities beginning in 1983.

PLATE 5.1-4 *Icebreakers are required to assist oil industry operations offshore in the Arctic. The KIGORIAK, which started operations in 1979, was the first icebreaking vessel to be built specifically for the Beaufort Sea. It is used both to support drillships and for research purposes.*

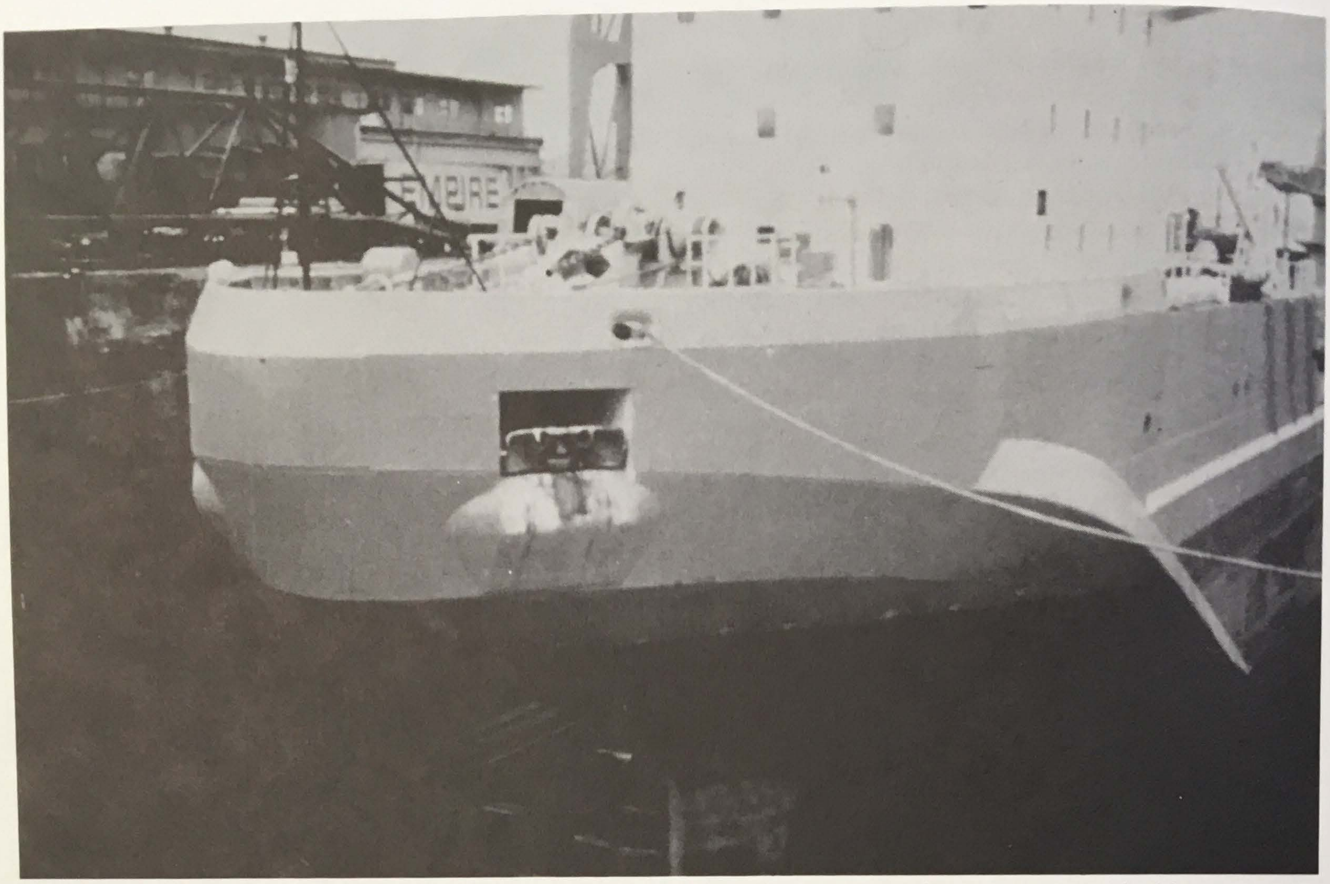


PLATE 5.1-5 *The KIGORIAK is equipped with several special design features, two of which are shown in this photograph. The reamer bow cuts a channel through the ice two metres wider than the hull. This reduces friction and increases the ship's capability to move through ice. The ice-knife prevents the ship from riding up excessively on ice floes and thus reduces the likelihood of the ship getting stuck in heavy ice.*

PLATE 5.1-6 *A third special design feature of the KIGORIAK is the water spray system in the bow. The water pumped out provides a lubricating layer between the hull of the ship and the sea ice.*

In the longer term, a large icebreaker is being designed that, if built, would be capable of navigating through ice conditions in Arctic waters throughout the year. This ship will incorporate the most advanced design concepts available and will meet Class 10 icebreaking standards.

The design, shown in Figure 5.1-4, is for a vessel 150 metres long with a beam of 30 metres that will displace approximately 24,000 tonnes. The ship will have a twin screw propulsion system powered by four diesel engines providing a total shaft power of 45 MW.

5.1.2.1 Escort of Self-Propelled Vessels

The traditional use of icebreakers around the world is to open a channel through the ice so that other self-propelled vessels can manoeuvre and make way. Most icebreakers are designed exclusively for this purpose, having no capability for other duties such as towing or cargo carrying. The CCGS JOHN A. MACDONALD, a Class 3 icebreaker, is an example of this type of vessel. This ship is shown in Plate 5.1-7 being used for research on icebreaker design.

In the Beaufort Sea exploratory operations, the Canmar icebreakers have been used for escorting purposes relatively infrequently. Drillship operations have been confined for the most part to open waters, thus requiring an escort only in the spring when they leave the winter mooring site for the drill sites and again in the fall when they return. Escort service is also provided for new vessels sailing into the Beaufort Sea around the coast of Alaska and occasionally for smaller supply ships working late in the year.

One might conclude that in the future, as operations are extended to a year-round basis, there would be more demand for escort services. It is probable, however, that most of the new vessels coming into the Beaufort Sea will have an icebreaking capability themselves. If Arctic tankers were used to carry oil from the Beaufort Sea-Mackenzie Delta Region, through the Northwest Passage, they would have at least 113 MW of power and would be Class 10 icebreaking vessels capable of handling any type of ice in the Arctic at any time of the year. Thus, they will not need an escort except in exceptional circumstances.

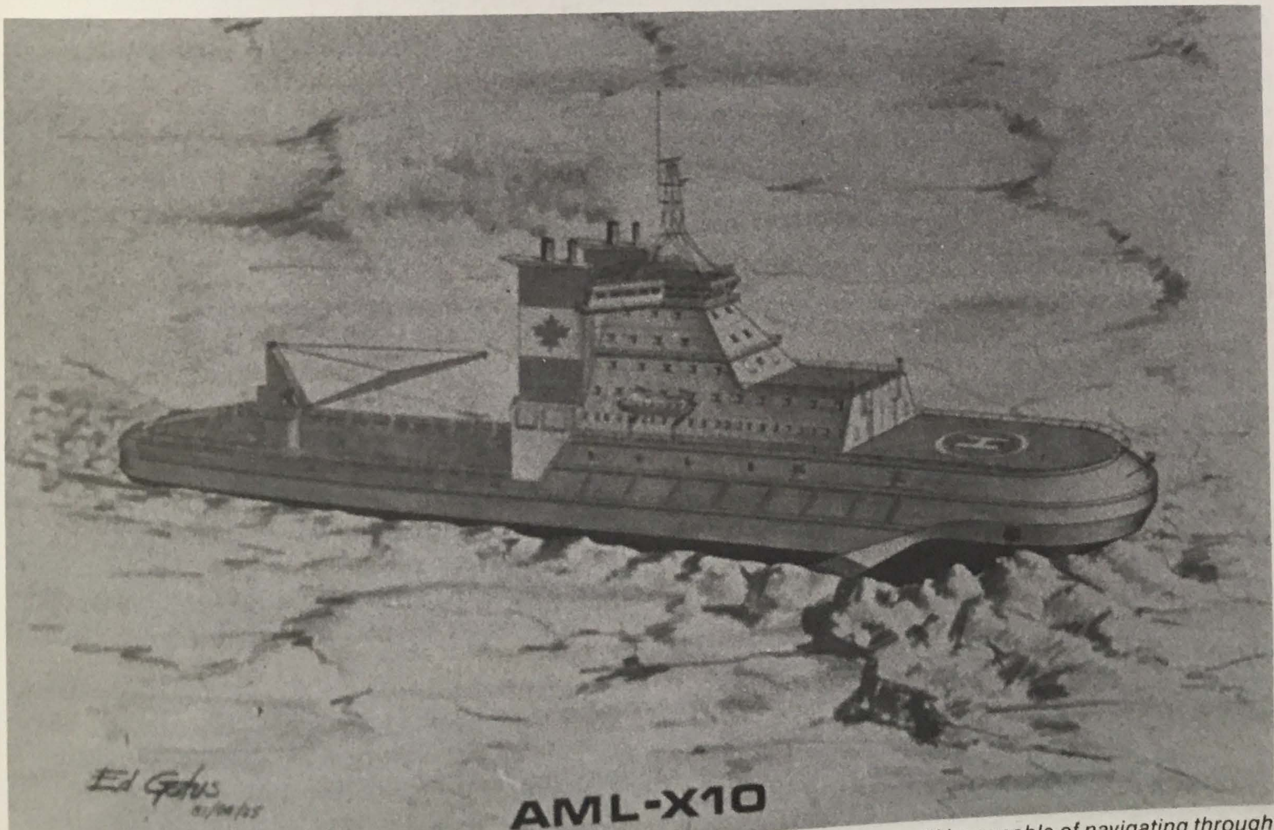


FIGURE 5.1-4 *A large icebreaker is currently being designed to Class 10 standards. It will be capable of navigating through severe ice conditions in Arctic waters throughout the year to support offshore operations.*

PLATE 5.1-7 *Canadian Coast Guard icebreakers have been operating in the Arctic for years for resupply of northern communities, escort of ships and research projects. The Canadian Coast Guard ship JOHN A. MACDONALD, shown in this photograph, was chartered by Dome in 1978 to, amongst other things, conduct research on late season drilling operations in the Beaufort Sea.*

5.1.2.2 Emergency or Rescue Service

Another traditional use of icebreakers is to go to the aid of vessels in distress in ice-bound waters. The latter may be vessels that got into trouble because ice conditions were worse than expected or vessels suffering some sort of mechanical failure while operating in ice. Since most of the vessels of the future will have substantial icebreaking capability almost any vessel in the fleet could be used for rescue service. Nevertheless, the future fleet will likely be equipped with several Class 10 vessels, some of which will be assigned to standby in the case of emergency.

5.1.2.3 Ice Defence

One of the major roles of icebreakers used in the Beaufort Sea during the last six years of drilling operations has been to defend the drillships from ice and to break them out of their winter mooring sites. Since the drillships are moored in a fixed location on a fixed heading they must be protected from ice which has the potential of moving them off location.

The drillships were originally designed to drill only in the open water season. Experience has shown that use of these open water drilling systems could be extended if ice moving against the drillships was broken into small pieces. A technique was developed for late season operations after extensive engineering calculations and model work. The CCGS JOHN A. MACDONALD was chartered by Canmar in 1978 for a demonstration project. The project involved continued operation of a drillship for shallow well drilling after ice had formed on the Beaufort Sea. The ice, which is usually moving, was broken into smaller pieces by the CCGS JOHN A. MACDONALD manoeuvring in a figure eight pattern about one mile 'upstream' of the drillship. The smaller Canmar icebreakers worked in between the CCGS JOHN A. MACDONALD and the drillship, breaking the ice into still smaller pieces and deflecting the larger pieces away from the drillship. This made it possible to drill until late November in 1978 and demonstrated that the limits of drilling with conventionally moored drilling vessels was dependent on the capability of the defending ships to break the encroaching ice. Plate 5.1-8 shows an icebreaker defending a drillship.

Ice defence has also been required during the open water drilling season. At this time ice floes, either from the Polar Pack or remnants of landfast ice, frequently enter the drilling area. The icebreakers are used to locate this ice and either break it into manageable pieces or deflect it around the drillship.

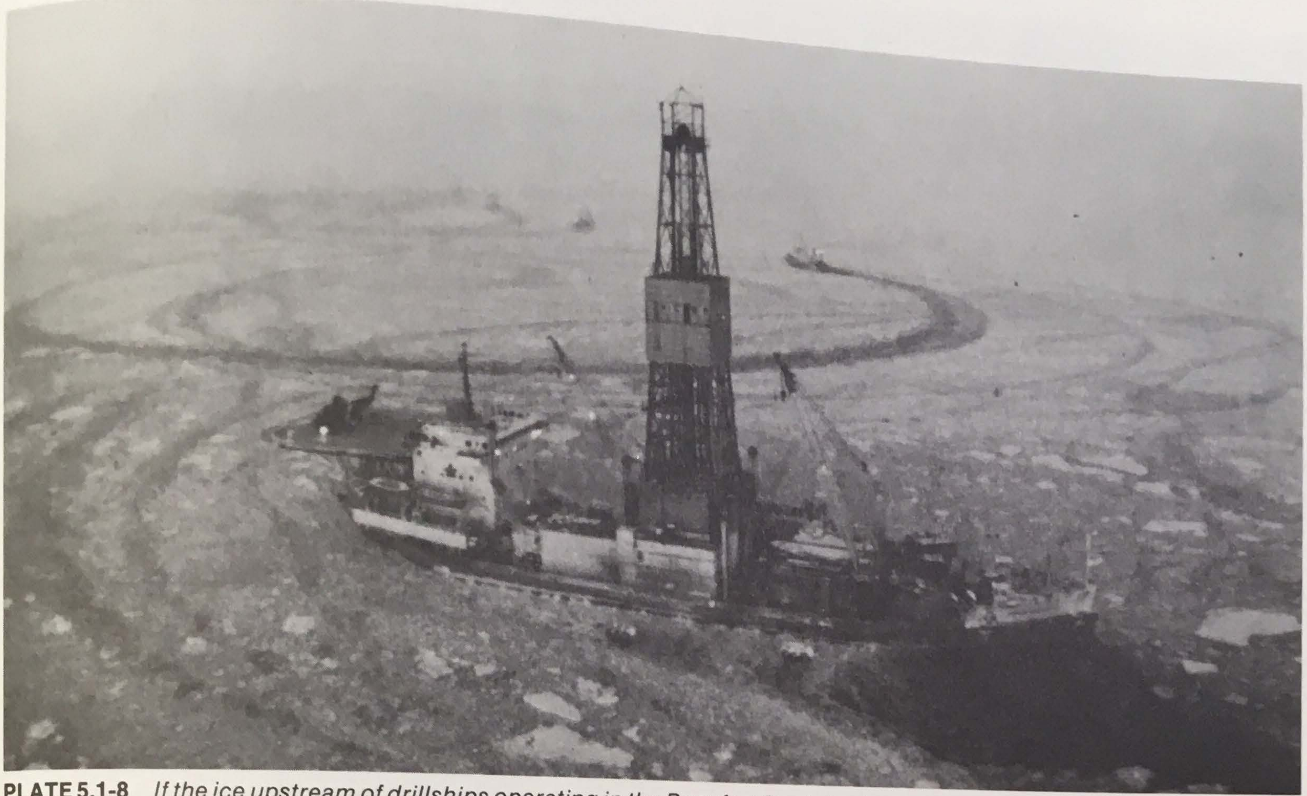


PLATE 5.1-8 *If the ice upstream of drillships operating in the Beaufort Sea is broken up by icebreakers, drilling may continue for a longer season. For example, in 1978 this enabled drilling to continue until late November when the ice was nearly one metre thick. An icebreaker is shown here defending a drillship in this way.*

Future plans for both exploratory and producing operations are oriented towards systems that will be able to resist expected ice forces in the passive mode. Islands built in shallow water have successfully resisted ice forces in the passive mode for the last several years, so that no icebreaker defence was required during the winter months. The ice forces, in this area are not as large as those experienced in deeper water because the ice is landfast through most of the winter. Moving ice in the fall and spring is grounded on the island beach and no significant problems have been encountered with moving ice.

Deep water island systems (exploratory islands, production islands and APLAs) are being designed to resist any type of ice condition in the passive mode, so that icebreaker defence will not be required. An APLA, however, will be the hub of such a diversified spectrum of activities that one icebreaker of Class 6 to Class 10 may be provided with each of these installations.

Future floating drilling systems will be circular or conical in configuration presenting an icebreaking 'bow' to moving ice regardless of the direction of ice movement. The bow of a conventional drillship can withstand ice forces ten times greater than the sides; hence the search for systems that do not have a 'broadside' exposure. Massive mooring systems are still required for the circular or conical drill systems in order to provide sufficient restraint force that the vessel can break the type of ice expected during winter months. The extended season floating drilling system, however, will still require an icebreaker at times for defending it against ice conditions more severe than those commonly experienced.

5.1.3 STANDBY BOATS

Government drilling regulations require that a standby vessel be in the vicinity of a drillship for most of the drilling activities. This boat must be capable of accommodating the entire crew of the drillship in the event of a drillship evacuation. At the present time there is one standby boat assigned to each of the four drillships (Plate 5.1-9).

As year-round operations develop, standby boats will play a smaller role in the Beaufort Sea. Islands do not require standby vessels because there is no 'sinking' risk and personnel can usually retreat to the ice. It will not be practical to have standby vessels for extended season floating drilling systems other than the icebreaker escort which will be in attendance most of the time.

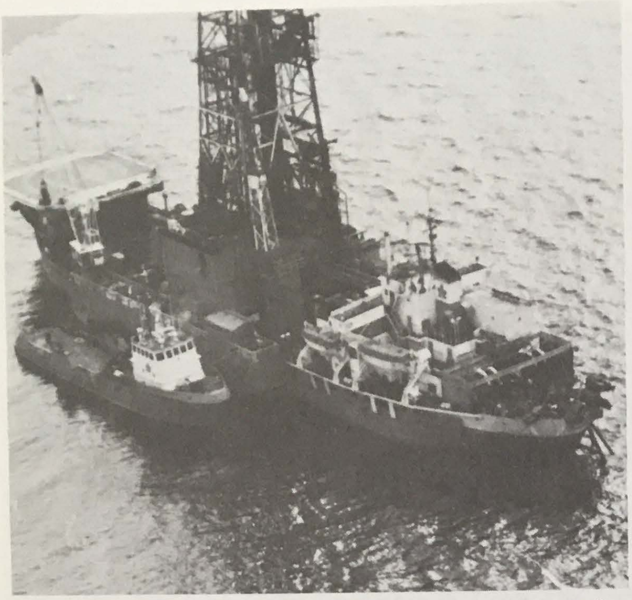


PLATE 5.1-9 *Each drillship is accompanied by a standby vessel to assist in the case of an emergency. This boat can accommodate the entire drillship crew if an evacuation should become necessary.*

5.1.4 TUGS, BARGES, AND SMALL BOATS

Every marine operation has its requirements for a variety of smaller craft. Barges are the traditional low cost method of moving cargo in relatively calm water conditions. Tug boats are used to push or tow barges (Plate 5.1-10) and help manoeuvre large ships. Small boats are involved in miscellaneous duties, such as moving people and small pieces of equipment from place to place.

PLATE 5.1-10 *Heavy cargo for offshore activities is moved by barges pushed or towed by tugs.*

Ocean-going tugs are used for some offshore operations and for towing heavy equipment and construction components into the Region from the west coast through the Bering Strait. Ocean-going, ice-reinforced barges, such as the ARCTIC BREAKER shown in Plate 5.1-11, are used in these operations.

Offshore construction operations create even more requirements for these craft because of the wide variety of activities. For example, in dredging, small tug boats reposition anchors, relocate floating dredging lines and move accommodation and crane barges into position, while small high speed boats deliver crew and light supplies. Plate 5.1-12 shows a construction fleet in the Beaufort Sea viewed from a dredge.

To illustrate a unique tug vessel which might find use in Beaufort Sea operations in the future, the following describes the Archimedian Screw Tractor (AST). The AST is an amphibious tractor capable of operating in and around ice covered waters. The craft consists of a watertight rectangular body supported on two horizontal watertight cylindrical pontoons. These cylinders have an external helix thread fitted and by rotating the cylinders, the craft can be moved in any direction. The AST is demonstrated in Plate 5.1-13.

Because of its amphibious capability the AST can be used under conditions where other more conventional vehicles cannot operate. This particularly applies during freeze-up or break-up conditions. This craft, because of its high towbar pull capacity and relatively low speed, will most likely be used as a tractor unit towing sleds or special barges for resupply purposes. Tests on the craft AST 002 have demonstrated its ability to tow up to 70 tonnes of drilling mud on three sleds over typical ice conditions in the Prudhoe Bay area.

5.1.5 DREDGES

5.1.5.1 Conventional Dredges

Several different types of dredges are presently being used in the Beaufort Sea. The BEAVER MACKENZIE, one of the first to enter the Beaufort, is a stationary suction dredge which has the capability of pumping up to 70,000 cubic metres per day of material from the sea floor. She can operate in water depths up to 45 metres; however, as water depth increases, the daily dredge capacity of the system decreases. Dredge material is discharged to the construction location by floating pipeline or is transported by hopper barges.

The AQUARIUS shown in Plate 5.1-14, is a self-propelled cutter suction dredge, which has the capability of moving up to 100,000 cubic metres per day of material from the sea floor and can operate in up to 35 metres of water.

PLATE 5.1-11 *Ice-reinforced barges have been built to bring cargo into the Beaufort Sea and to be used as storage and transportation barges in the area.*

PLATE 5.1-12 *Offshore construction operations require vessels for a wide variety of activities. Shown here is a construction fleet in the Beaufort Sea viewed from a dredge.*

PLATE 5.1-13 *Research and development continues on transportation equipment for the Arctic. Shown here is the Archimedian Screw Tractor, an amphibious vehicle which can be operated in and around ice covered waters. It is still in the experimental phase but may have an application for moving cargo or personnel in Beaufort Sea activities, particularly around islands in winter.*

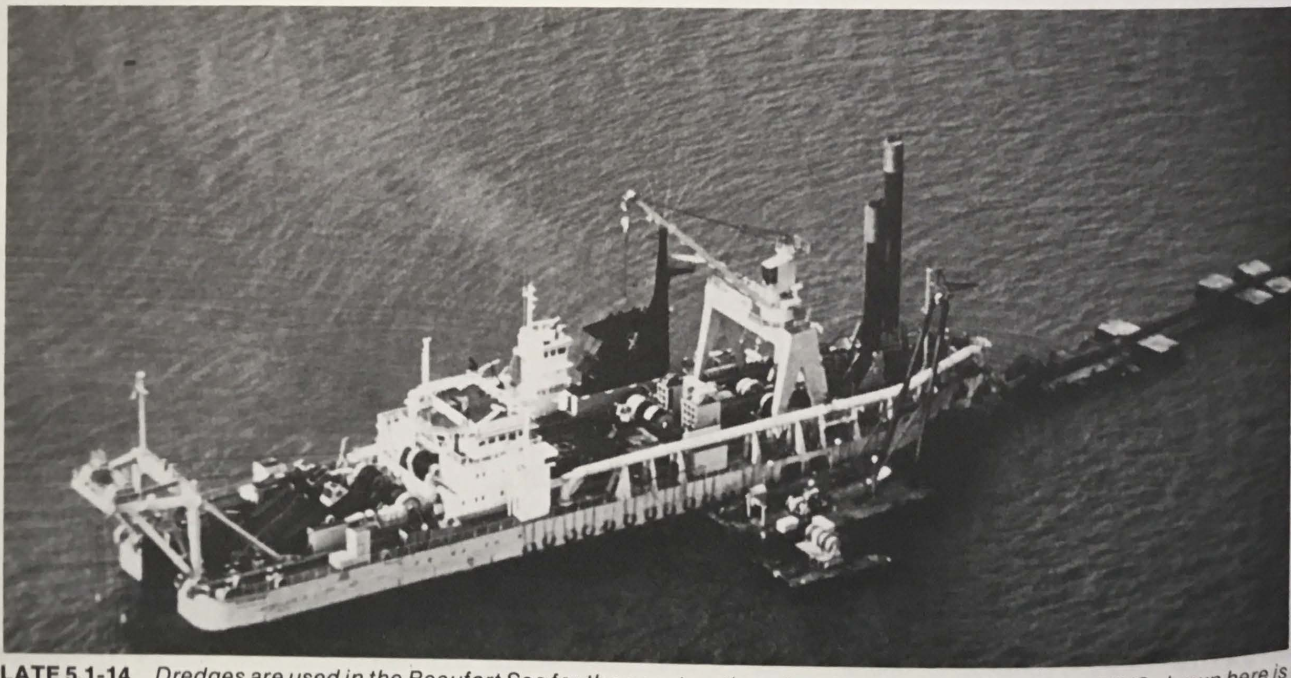


PLATE 5.1-14 *Dredges are used in the Beaufort Sea for the construction of artificial islands. The AQUARIUS shown here is a self-propelled cutter suction dredge which can be used to dredge up to 100,000 cubic metres of material per day from the sea floor. Dredged material is moved to the required location by pipeline or hopper barges.*

Since dredged material sometimes has to be moved over significant distances, dredges with self-contained hoppers have begun to be used in the last few years. Plate 5.1-15 shows the HENDRIK ZANEN trailing suction hopper dredge returning empty to obtain a new load of dredged material. When the hopper is full, the vessel transports the material to the artificial island site where it is discharged. This type of dredge provides an effective fill placement method for sites remote from suitable sources of dredged material. Plate 5.1-16 shows the suction arm on this dredge and Plate 5.1-17 shows the loaded dredge operating in heavy seas.

PLATE 5.1-15 *The HENDRIK ZANEN, a trailing suction hopper dredge, has self-contained hoppers for carrying dredged material to construction sites. The dredge is shown here returning empty to the borrow site.*

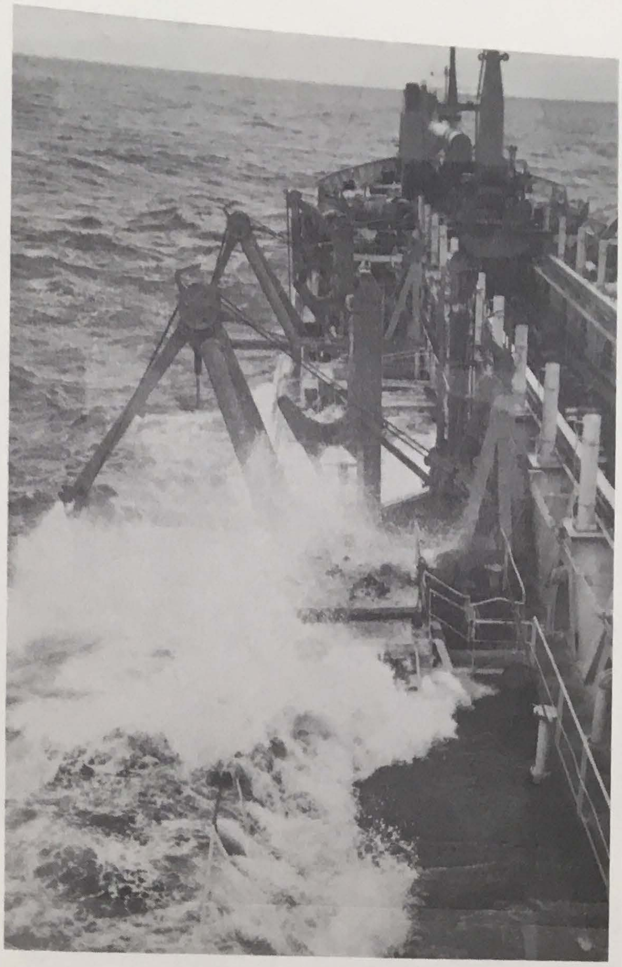


PLATE 5.1-17 *When loaded, the hopper dredge lies low in the water. The loaded HENDRIK ZANEN is shown here operating in rough seas.*

PLATE 5.1-16 *The suction arm on the HENDRIK ZANEN through which dredged material is gathered from the sea floor.*

5.1.5.2 Arctic Dredges

The large sand and gravel structures required for offshore development have necessitated the design of large capacity, icebreaking hopper dredges such as shown in Figure 5.1-5. These Arctic dredges with a capacity of 25,000 cubic metres of dredged material would be capable of operating in water depths up to 80 metres through most of the year.

The Arctic dredge features include a hull design and power plant meeting Arctic Class 6 icebreaking requirements with retractable dredge pipes which extend to 80 m water depth. The draghead and suction pipe will be protected from ice by moon pool enclosures. The icebreaking hull and large horsepower will enable the dredge to operate for an extended season independently, in the Beaufort Sea.

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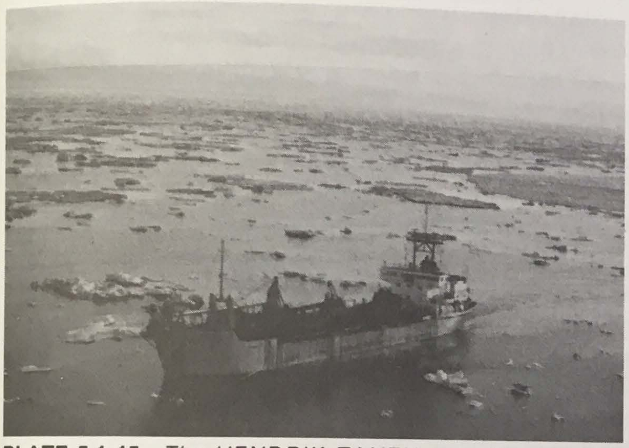

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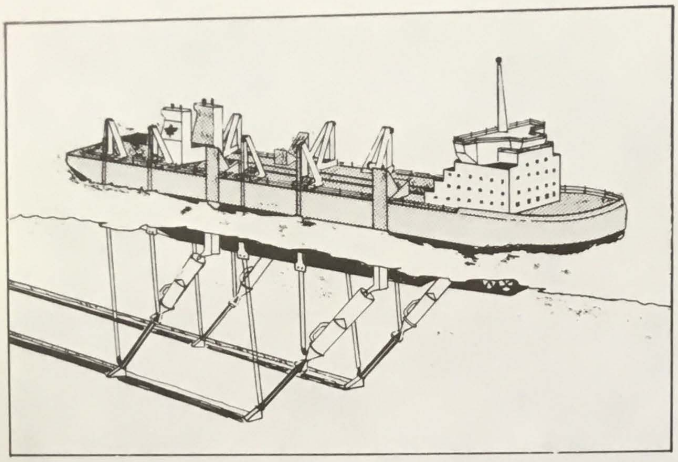


FIGURE 5.1-5 *The large sand and gravel structures required for Beaufort Sea development have necessitated the design of very large capacity icebreaking hopper dredges. If built, these Arctic dredges will have a capacity of 25,000 cubic metres of dredged material and be able to operate in water up to 80 metres deep. These will be the largest hopper dredges in the world.*

5.1.6 CRANE BARGES

Heavy equipment required for offshore construction, such as cranes, are normally mounted on work barges and towed to site. However, there is one specially constructed crane barge in use, the CANMAR CONSTRUCTOR (formerly PACIFIC SUPPORTER) shown in Plate 5.1-18. She is not self-propelled but has construction equipment and accommodation facilities built into the barge.

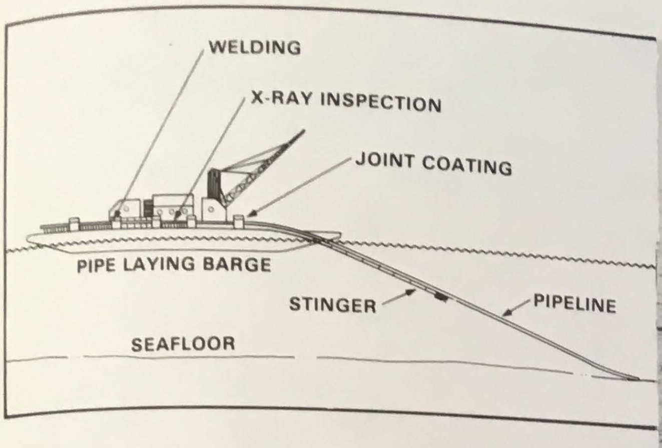
This barge, built in Singapore, is 88 metres long by 24 metres wide, with a depth of 6 metres, a maximum draft of 4 metres and a gross tonnage of 4,539 tonnes. She has a clear deck area of 768 cubic metres, a helipad, cranes, winches and pile driving equipment. The main crane, mounted on the end of the barge, has a lifting capacity of 180 tonnes and an outreach of 14 metres. This is supplemented by a 9 tonne crawler crane. Other equipment includes two 9 tonne winches, two 4 tonne winches and pile-driving equipment. There is also a moon pool which may be used for any diving system.

The barge has accommodation for 220 people, comprising cabins, recreation rooms and associated facilities. There is a freshwater storage capacity of 2,153 cubic metres, a sewage treatment unit and an incinerator.

5.1.7 PIPE-LAYING BARGE

A pipe-laying barge of the type that could be used in the Beaufort Sea - Mackenzie Delta Region is shown in Plate 5.1-19. The barge has a helipad for transfer of personnel and a large crane for handling the pipe sections which are joined together on the barge then fed out of the back and onto the sea floor. Typically, such a barge might have a 5 MW propulsion system for moving at low speed while laying pipe, however, it would probably be towed into the region from a southern centre by tug.

PLATE 5.1-18 *The CANMAR CONSTRUCTOR, a crane barge used for construction projects in the Beaufort Sea, has construction equipment and accommodation facilities built in.*



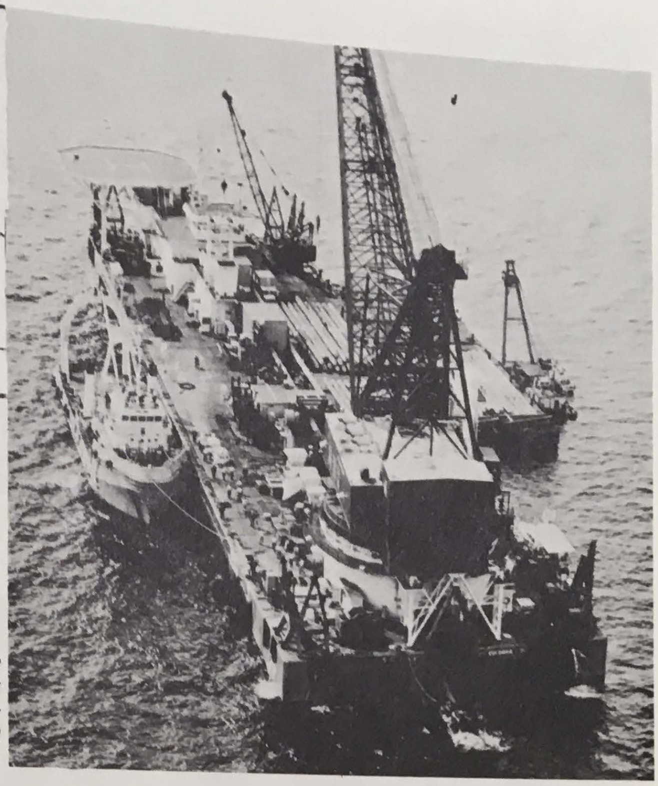


PLATE 5.1-19 *A pipe-laying barge of the type that could be used for laying subsea pipelines in the Beaufort Sea is shown here. The barge has a helipad for transfer of personnel and a large crane for handling the pipe sections which are joined on the deck then fed onto the sea floor.*

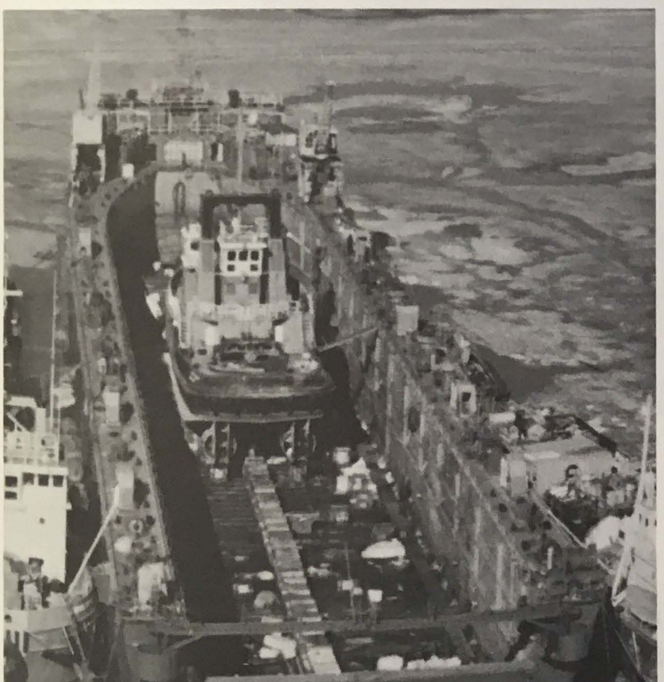


PLATE 5.1-20 *Marine vessels in use in the Beaufort Sea remain there year-round. There are thus two mobile drydocks in use in the Region, the smaller of which is shown here.*

5.1.8 FLOATING DRYDOCKS

All marine vessels used in the Beaufort Sea, other than barges delivering equipment from southern Canada, remain in the region year-round. For this reason, all repairs must also be carried out here. To make this possible, there are two drydocks in use in the area (1982). These docks have a water ballast system operated by diesel pumps to allow submersion and refloating. The smaller of these two is shown in Plate 5.1-20.

The CANMAR CAREEN drydock, which arrived in the Beaufort Sea in 1981 is shown in Plate 5.1-21. It is essentially a barge 137 metres long by 49 metres wide with corner wing walls. It has a maximum draft in transit of 5.5 metres and a corresponding deadweight of 2,177 tonnes. It has maximum lifting capacity of 27,000 tonnes with 1.2 m of freeboard. The deck area is large enough to drydock four supply vessels at one time and can handle the largest ships presently in the Beaufort, including the drillships.

5.1.9 ACCOMMODATION BARGE

While there are onshore accommodation facilities at Tuktoyaktuk, additional accommodation must be provided at some distant work sites. At present, this is provided by accommodation barges that are towed to

PLATE 5.1-21 *The CANMAR CAREEN drydock is shown here being used for repairing a drillship in McKinley Bay. The drydock is essentially a submersible barge with corner wing walls.*

a work site by tug. When permanent accommodation is required similar accommodation barges may be incorporated into an island structure by building up dredged material around the barge.

In the Beaufort Sea there are two accommodation barges currently in use (1981). The NWD 208 Camp Barge which can accommodate 120 personnel and has been used in the Mackenzie Delta area since 1974 is shown in Plate 5.1-22. This barge is 110 metres long and 15 metres wide with a registered tonnage of 7,025 tonnes. It has a fuel storage capacity of 1,568 cubic metres and can store up to 422 cubic metres of water. On the upper deck of the barge there is a helicopter pad, water desalination plant, heating furnaces and offices. On the mid and main decks there are dormitories, a kitchen, dining room and first aid room. On the lower deck there is a sewage treatment plant,

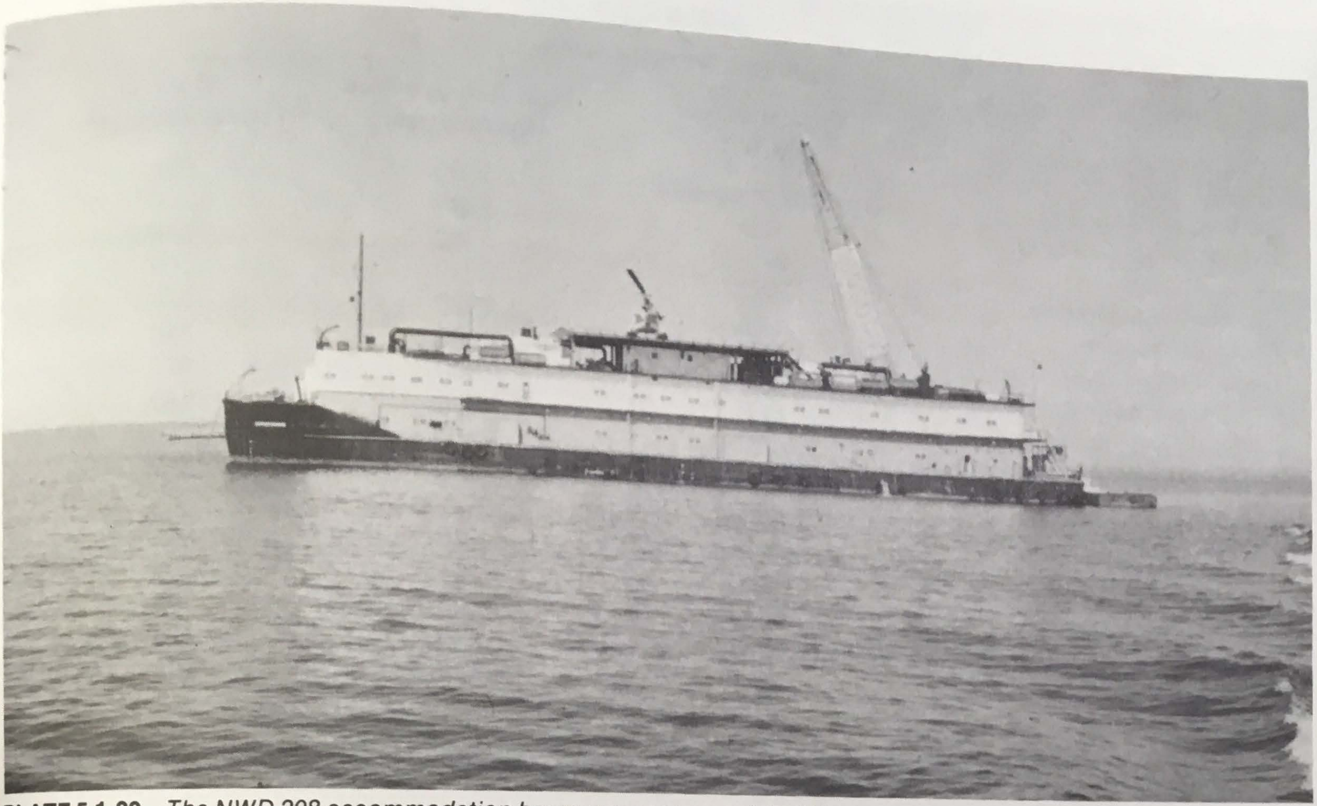


PLATE 5.1-22 *The NWD 208 accommodation barge can accommodate 120 personnel and has been used in the Mackenzie Delta area since 1974.*

diesel electric generator, cold and dry storage rooms, more offices and recreation rooms. Fuel and water is stored below. This accommodation barge is thus completely self contained.

The NWD 205 accommodation barge has comparable facilities to the NWD 208 but is rather different in shape, being 58.5 metres long but 30 metres wide. It is smaller than the NWD 208, having just one upper deck, a registered tonnage of 3,120 tonnes and accommodation for 60 personnel. This barge has also been used on a year-round basis in the Mackenzie Delta area.

In December 1981, Gulf purchased two coastal ferries for the purpose of providing warehousing, shop space, offices, as well as personnel accommodation. The intention is to renovate these two vessels, deliver them to the Beaufort Sea and operate them as part of a marine supply base.

5.1.10 POTENTIAL ENVIRONMENTAL DISTURBANCES

All of the marine vessels (ships, barges, dredges, etc.) which will be used in the Beaufort Sea have the same potential pollution sources, only the magnitude will vary. The reader is referred to Volume 4 for impact assessment. Table 5.1-1 lists typical vessel types to be used in the Beaufort Sea. Opposite each type are approximate engine power, fuel consumption and days of operation per year. Emission and discharges from the vessels are a function of engine size and operating days per year.

5.1.10.1 Atmospheric Emissions

The primary source of atmospheric emissions is exhaust from the ships' engines. On board incineration of solid waste also contributes to atmospheric emissions on some of the larger or specialized vessels (e.g. accommodation barges) but this is usually very small in proportion to the engine exhaust. Typically, carbon monoxide, carbon dioxide, water vapour, smoke, odor, and oxides of nitrogen make up the exhaust products. Diesel fuel exhaust emission factors have been used to determine typical atmospheric emissions from the various vessels.

The total atmospheric emissions from marine vessels will be in the order of 103 kilograms per tonne of fuel burnt. Based upon the fuel requirements shown in Table 5.1-1, the following air emissions are estimated:

- All smaller vessels and vessels relatively station-

TABLE 5.1-1 TYPICAL VESSEL TYPES	Typical Power (M.W.)	Fuel Requirement (tonnes/year)	Days of Operation/year
Conical Drilling Unit	(Not self-propelled)	1990	300
Conventional Drillship	2.5	1940	20*
Arctic Dredge	37.3	6850	240
Conventional Dredge	22.3	2610	105
Class 2 Icebreaker	7.5	1470	240
Class 3 Icebreaker	9.0	4860	240
Class 6 Icebreaker	20.1	7460	330
Class 10 Icebreaker	44.8	14040	330
Accommodation Barge	(Not self-propelled)	130	350
Crane Barge & Pile Driving Barge	(Not self-propelled)	130	350
Tug	2.1	330	105
Pipe-laying Barge	5.2	480**	105
Dry Dock	(Not self-propelled)	240	330
Miscellaneous Boats	2.1	480	105

*For remainder of open water season (approx. 105 days) the conventional drillship was assumed to be drilling - see 'Drilling Systems' for emissions.
**Estimated

ary for most of the year (barges) release less than 50 tonnes/year of atmospheric emissions.

- Dredges typically release emissions in the range of 300 to 700 tonnes/year whereas icebreakers typically release emissions of 150 tonnes/year for the smallest, up to 1,500 tonnes for the largest (Class 10). The greater amounts are primarily a function of the vessels year-round activity and the larger power capabilities employed.

5.1.10.2 Heat Emissions

The major source of heat emission is the water used to cool the ships' engines. This water is discharged into the sea at approximately 15°C.

Typical heated water discharges from the various vessel types are estimated below:

- From the smaller vessels, $5x10^9$ to $9.5x10^9$ Joules/hr of heat could be released to the surrounding water.

- For the larger vessels $1.3x10^{10}$ to $4.4x10^{10}$ Joules/hr of heat could be released.

Other sources of heat emissions are engine exhaust and the incineration of solid wastes onboard. Both of these types of emissions are issued into the atmosphere at a temperature high enough to induce sufficient plume rise for dispersion of the emissions.

5.1.10.3 Liquid Effluents

The major source of liquid effluents is the seawater used to cool the ships' engines. Other sources of liquid effluent are treated domestic sewage and bilge water.

5.1.10.4 Solid Wastes

Solid wastes generated onboard ship will be separated into combustible and noncombustible components. With the exception of the smallest vessels, the combustible material will be incinerated onboard and only the residue or ash will remain to be discarded. This residue from incineration and the noncombustible waste (approx. 14% of total solid waste) will be stored on the ships and taken to shore for ultimate disposal.

5.1.10.5 Vessel Disturbance

Vessel noise and illumination are potential sources of disturbance to marine animals. Illumination will occur during both the day and night and primarily in the atmosphere, not underwater. Noise generated by the operation of the ships' engines and other equipment will be audible in both the atmosphere and underwater.

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Preliminary estimates of illumination suggest light from the vessels could range from 40 to 50 lux with the exception of the stationary cutter suction dredges which require a lot of light - up to 215 lux - to work during the winter nights.

Noise estimates, although highly speculative at this time, could range from 60 to 80 dBA at 10 metres in air or maybe audible in an area of 5 to 6 square kilometres. Underwater noise levels for support vessels are described in Chapter 2 of Volume 4.

5.1.10.6 Personnel-Related Disturbances

The number of people onboard marine vessels is used to determine the quantities of personnel-related disturbances such as solid waste and domestic sewage. Table 5.1-2 lists the expected personnel numbers by vessel type.

TABLE 5.1-2

NUMBER OF PERSONNEL BY VESSEL TYPE

Marine Vessel Type	Typical Personnel on Board
Supply Vessels	12
Icebreakers - Class 3	20
Icebreakers - Class 6	24
Icebreakers - Class 10	44
Accommodation Barges	15
Conventional Dredges	44
Arctic dredges	54
Tugs	12
Crane Barges	12
Pipe-laying Barges	58
Floating Drydocks	53
Support, Vessels (misc.)	11

5.2 AIR SUPPORT SYSTEMS

The development of the Beaufort Sea-Mackenzie Delta Region depends significantly on air support systems. Long range aircraft are used to transport personnel, perishable foodstuffs and emergency cargo from southern centres. Helicopters and short take-off and landing (STOL) aircraft are used to ferry personnel and some cargo to offshore locations and remote sites in the Mackenzie Delta. Aircraft are also the essential component of the emergency response capability in the Region. This section describes the typical aircraft used to support the activities.

5.2.1 HELICOPTERS

The helicopter is an essential support system for every offshore drilling and producing operation, excepting perhaps those conducted within sight of shore. The oil industry is probably second only to the military in the use of helicopters on a worldwide basis.

The principal use of helicopters is to transport people since they are faster and more comfortable than boats. They are also used to transport small loads of cargo required for emergency purposes although specialty helicopters are available, such as the Bell 412, which can carry up to 2.2 tonnes slung on a cable beneath the fuselage.

Most offshore flying is done with twin engine helicopters. Typical helicopters used in the Region include the Bell 212, Sikorsky S-61 (Plate 5.2-1), Sikorsky S-76 and the Puma. Other types of helicopters will be chartered as the need arises. In the future the use of the civil version of the Boeing Chinook helicopter (Boeing 234-Plate 5.2-2) or comparable craft could radically alter the pattern of offshore personnel transportation since this helicopter has a much greater payload/range than the rotary wing aircraft now in use. The helicopter requirements obviously vary in accordance with the number and nature of the offshore activities, the distance from the helicopter base and the frequency of crew rotation. The total predicted helicopter requirements, a function of the level of activity in the Region, are provided in Chapter 3.

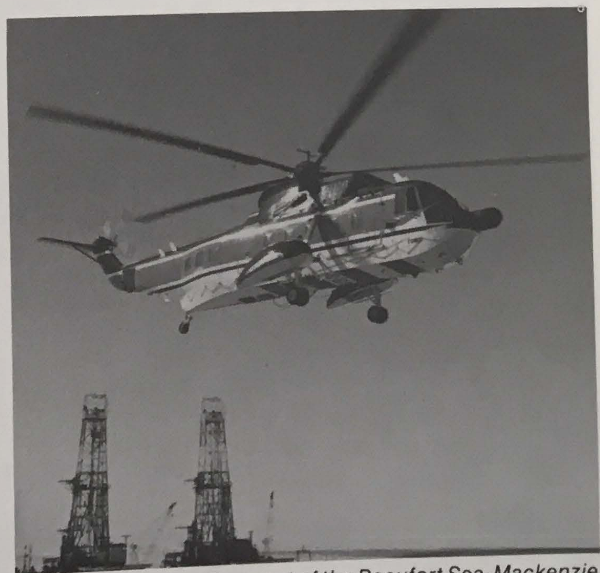

PLATE 5.2-1 *Development of the Beaufort Sea-Mackenzie Delta Region will rely heavily on air support and in particular helicopters. A Sikorsky S-61 is seen here transferring supplies and personnel to drillships.*

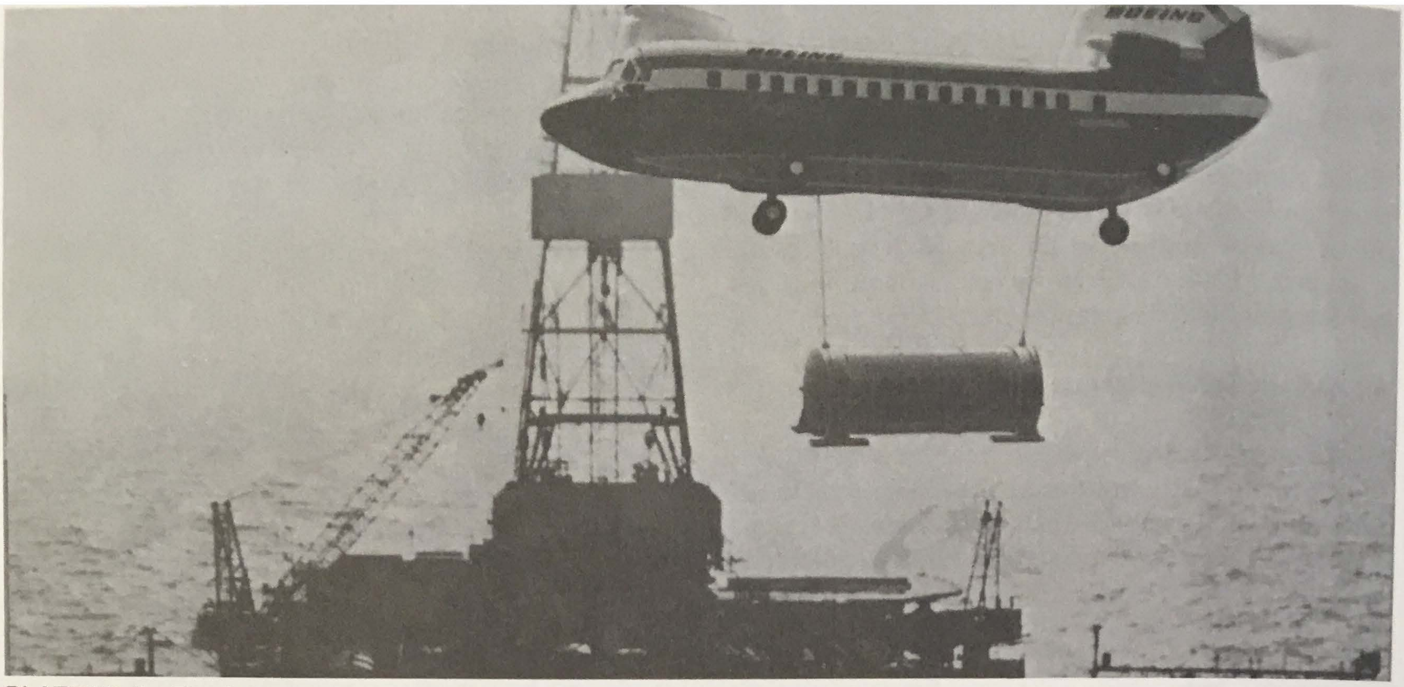

PLATE 5.2-2 *The Chinook Helicopter cruises at 140 knots and carries up to 44 passengers travelling as far as 960 kilometres. THis helicopter is designed to float in 10 metre waves without auxiliary flotation devices.*

5.2.2 STOL AIRCRAFT (Short Take-off and Landing)

The STOL aircraft has become an essential fixture in the Arctic where short, rough and poorly oriented airstrips are common. These powerful, turbo-prop planes require only a short landing strip for standard operation and with special tires can handle very rough terrain. The aircraft gives equally good performance from skis or floats.

In remote areas, the oil industry is very dependent on STOL aircraft such as the DeHavilland Twin Otter shown in Plate 5.2-3. Most remote land operations have short airstrips available so that people and supplies can be transported from the regions's support bases. In the Beaufort Sea-Mackenzie Delta Region there is considerable traffic between Inuvik and Tuktoyaktuk with STOL aircraft carrying people and materials that have arrived on scheduled airline flights from Calgary and Edmonton. The STOL aircraft also pick up workers from the surrounding communities and transport them to Tuktoyaktuk prior to transport to drilling and construction sites. They are also used to fly offshore ice reconnaissance missions.

5.2.3 LONG RANGE FIXED WING AIRCRAFT

The major operators routinely fly charter or company owned aircraft to the job sites in order to transport workers from southern centres. The most common aircraft presently used for this service are the Lockheed Electra and the Boeing 737 jet. Both of these aircraft carry a combination of passengers and freight and can fly nonstop to Tuktoyaktuk from either Calgary or Edmonton.

Larger aircraft are available if the demand is present. In the future Boeing 767 aircraft or equivalent, may be employed. They will be able to carry 230 passengers but will require a runway length of about 2,200 metres.

During the drilling season, the Boeing 737 as shown in Plate 5.2-4, transfers personnel and freight from Calgary and Edmonton on a daily basis. Similarly, the Lockheed Electra moves passengers and freight into the Region. The Lockheed Electra is shown in Plate 5.2-5.

Other long range aircraft which are used to move cargo are chartered as needed and include the Lockheed Hercules, the F-27, the Hawker-Siddley 748, and the Convair 440 and 580.

5.2.4 SMALL AIRCRAFT

A variety of small aircraft are used in remote oil industry activities for tours, the movement of small parts and small numbers of passengers. These aircraft carry from 4 to 7 people and vary from small single engine piston driven aircraft to small corporate jets. With the exception of corporate jets, they are usually chartered from local operators. As the level of activity in the Region increases, the oil industry will require increasing small aircraft support much of which could be provided by local charter operators.

PLATE 5.2-3 *In remote areas the oil industry is dependent on short take-off and landing aircraft such as the DeHavilland Twin Otter.*

PLATE 5.2-4 *Oil company owned aircraft are flown into the Region on a regular basis to transport personnel and cargo. Shown here is the Dome Petroleum Boeing 737.*

PLATE 5.2-5 *Esso Resources operates a Lockheed turboprop aircraft to carry supplies and personnel to the Mackenzie Delta.*

5.2.5 POTENTIAL ENVIRONMENTAL DISTURBANCES

The operation of rotary and fixed wing aircraft in the Region will generate two types of emissions, noise and atmospheric emissions. Land area disturbances related to airports are discussed in Section 5.3. The reader is referred to Volume 4 for a discussion of the impact assessment of aircraft services.

The types of engines powering aircraft in the Region are divided into three main categories; turboprops, turbojets (turbofans and piston-engined aircraft. Typical aircraft likely to be used in the Beaufort Sea Region include: the Boeing 737, Citation and Lear jets as examples of the jet aircraft, the Lockheed Electra, Twin Otter, Grummen, Dash 7 and Hercules aircraft as examples of turboprop aircraft, and Cessna 180 as an example of a piston-engined aircraft. The larger helicopters can be characterized as turboprop type and the smaller (2 passengers) helicopters characterized as piston-engined aircraft.

5.2.5.1 Atmospheric Emissions

Table 5.2-1 provides typical aircraft emission factors.

TABLE 5.2-1

EMISSION FACTORS PER LANDING AND TAKE-OFF CYCLE IN KILOGRAMS*

Aircraft	CO	NO_x[1]	Hydrocarbons	SO_x[2]
Jet				
Boeing 737-200	16.92	8.96	4.06	0.99
Cessna Citation	8.85	0.91	3.05	0.18
Learjet	5.11	1.58	1.70	0.42
Turboprop				
Lockheed L100 Hercules	22.12	19.65	8.91	0.83
Twin Otter	3.25	0.37	2.30	0.08
Piston				
Cessna 150	3.77	0.01	0.10	0.0

* Typical landing and take-off cycle, incorporates descent and approach from 3000 feet, touchdown, landing run, taxi-in, idle, shutdown, start-up and idle, check out, taxi-out, take-off and climb-out to 3000 feet.

1. Oxides of nitrogen as NO_2
2. Oxides of sulphur as SO_2

Source: 'Air Pollution Emission Factors for Military and Civil Aircraft', EPA, 1978.

5.2.5.2 Noise

Noise produced by aircraft is unique because the generated acoustic power is far greater than other conventional sources of noise. Noise is a byproduct of the aircraft's power plant and is caused mainly by the engines and propellers. Noise from turbojet engines is caused by the turbulent mixing of high velocity exhaust with the ambient air; hence, sound increases with increasing exhaust velocity. Turbofan engines, which have replaced turbojet engines in newer jet aircraft, have reduced noise levels because the exhaust velocity is less.

For propeller aircraft (turboprop or piston-type), the propeller is the dominant noise source during take-off. The turboprop aircraft is usually quieter than a comparable piston-type aircraft during take-off.

Noise levels, referenced as the Effective Perceived Noise Level, are measured at three locations during the landing and take-off cycle as shown in Figure 5.2-1. Approach noise level measurements are taken at a point 2,000 metres from the landing threshold on the extended centreline of the runway. Take-off noise level is measured at a point 6,500 metres from the start of the take-off roll on the extended centreline of the runway. Sideline noise levels during take-off are measured on a line parallel to and 450 metres from the extended centreline of the runway, where the noise level after take-off is greatest.

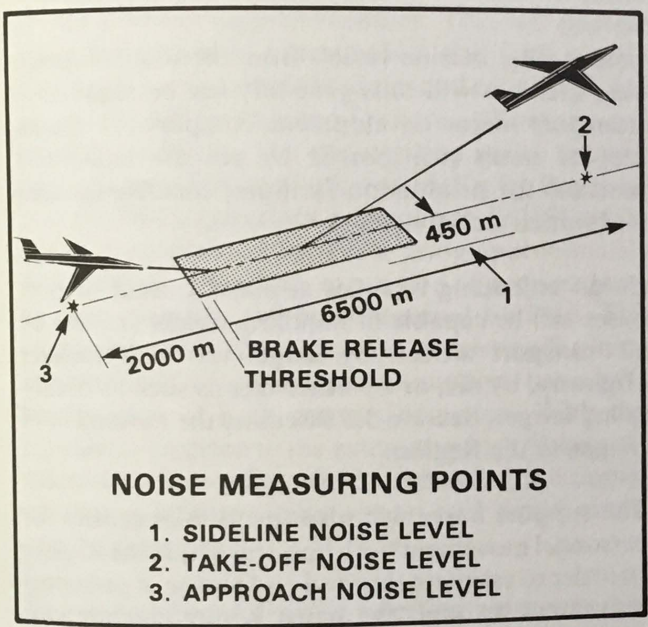

FIGURE 5.2-1 *Noise levels generated by aircraft are maintained and controlled. The effective perceived noise level is measured at three locations of a landing and take-off cycle.*

Noise levels from typical large fixed wing aircraft are provided in Table 5.2-2 and are recorded as the Effective Perceived Noise Level (EPNdB) at the aforementioned measuring location during landing and take-off. The Bristol Aerospace 146-100, a new generation jet airliner not yet in production, is included in the table as an example of future quieter jet aircraft.

A noise level contour, or "footprint," the area of land around an airstrip which would experience a particular noise level during take-off and landing, is shaped similar to the footprint shown in Figure 5.2-2. A noise contour or footprint is a single event contour of a particular noise level and is a function of aircraft weight, engine power settings, airport altitude, wind velocity, temperature, relative humidity and terrain. The shape and area of land within the footprint varies with the type of aircraft. For example, a 90 EPNdB footprint for a typical twinjet like the Boeing 737-200 would encompass about 19.4 square kilometres, a typical twin turboprop such as the Hawker Siddley 748 would encompass about 10.9 square kilometres, and the aforementioned Bristol Aerospace 146-100 has a reduced footprint area of about 5.7 square kilometres.

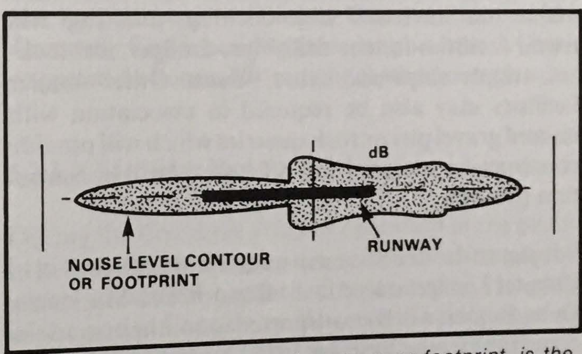

FIGURE 5.2-2 *A noise level contour, or footprint, is the area around an airstrip which experiences a particular noise level during take-off and landing. A typical footprint would be shaped similar to that shown here.*

TABLE 5.2-2

AIRCRAFT OPERATIONAL NOISE (EPNdB*)

Characteristics	Boeing 727-200	Boeing 737-200	Aircraft: Hercules L-100-20,30	Hawker Siddley 748	DHC-7 (Dash 7)	BAe 146-100
Approach Noise Level	100.4	100.6	101.5	103.8	91.0	97.0
Take-off Noise level	100.0	95.3	95.0	92.5	70.0	85.2
Sideline Noise Level (Take-off)	102.2	102.4	97.8	96.3	81	89.4

*Effective Perceived Noise Level

5.3 LAND SUPPORT SYSTEMS

Land-based support systems are those facilities that are external to the drilling and producing operations. Onshore support bases, construction camps and regional roadways are addressed in this section, as they are common facilities operating in support of drilling and producing systems. Other onshore land uses, such as foundations for drilling and producing systems and pipeline rights-of-way are described in Chapters 4 and 6.

5.3.1 SUPPORT BASES

Exploration activity in the Beaufort Sea - Mackenzie Delta Region has necessitated the establishment of support bases. At present Tuktoyaktuk, McKinley Bay and Inuvik serve this purpose but, as levels of activity increase with construction, production and further exploration activities, these will have to be expanded and others added. These bases will be centres to which all cargo is transported from the south, reorganized then distributed to work sites and project locations. They will also function as personnel terminals, having major airport facilities, where workers arriving from the south may transfer to smaller local aircraft in order to reach work sites. Some will also be major marine bases with docking, mooring and repair facilities for the drillships, dredges, icebreakers, supply ships and other vessels. Other smaller facilities may also be required in association with onland gravel pits or rock quarries which will provide construction material for offshore island construction projects.

Subject to the development assumptions identified in Chapter 3, oil produced in the Beaufort Sea-Mackenzie Delta Region will be transported to southern markets on a commercial basis by 1986. At that point critical equipment and capital development projects will be well underway and support base facilities will be substantially increased over present levels.

Assuming that production development is proceeding at the intermediate rate, approximately 169 thousand tonnes of consumables will be needed for exploration and production drilling in 1986. In addition, 290 thousand tonnes of fuel will be required to power the marine vessels and drilling rigs, and 15 thousand tonnes of other routine supplies will be required to support the drilling and construction projects.

Table 5.3-1 summarizes the major consumables projected to be shipped to and distributed from the northern support bases in 1986 at the intermediate rate of production.

TABLE 5.3-1
MAJOR CONSUMABLES REQUIRED 1986
INTERMEDIATE PRODUCTION RATE

Item	Tonnes 1986
Tubulars	19,000
Mud Products and Cement	147,000
Other Drilling Consumables	1,000
Pipe - Lateral	2,000
Fuel - Drilling	37,000
Fuel - Marine Operations	228,000
Fuel - Support Bases	4,000
Fuel - Air Operations	21,000
Foodstuffs	6,000
Miscellaneous Supplies	9,000
Total	474,000

It has been assumed that major components for the construction of islands, production facilities and APLA's will be transported directly to the construction sites by marine vessels from the south. Support base facilities will thus generally not be required to transport major development components. Examples of items transported by sea are equipment modules for production facilities, concrete caissons and similar bulky items.

Cargo unloading facilities at major coastal support bases will be capable of handling freight arriving by all transport modes: by barge, via the Dempster Highway, by air, or by other means such as ocean-going barges. Section 5.6 discusses the movement of freight to the Region.

The support bases will also function as centres for personnel movement both into and within the Region. In order to estimate the level and nature of personnel movement through the bases, several assumptions are necessary. Firstly, all personnel entering or leaving the Region will travel by air. Secondly, a large proportion of personnel will be southerners who will rotate between northern work locations and southern centres on two to four week schedules. Thirdly, all personnel travelling to or from work areas will pass through one of the support bases. Fourthly, at least two of the support bases will receive long range aircraft operating directly from the southern supply centres, thereby minimizing the number of transfers and the length of the rotary wing transfer flights, while increasing the flexibility of regional air operations.

It is estimated that at the intermediate rate of production the total number of personnel required on-site at any one time in 1986 (probable year of first oil production) will be approximately 3,500. The system of rotating personnel to southern destinations on a regular basis will necessitate a further 2,500 oil industry personnel. To accommodate such a personnel rotation schedule, approximately 13 return flights per

week by Boeing 737 aircraft, or 8 weekly flights by Boeing 767 aircraft will be required.

The majority of the personnel arriving at the support bases from the south must be transported to and from work locations away from the bases. Approximately 90% of these workers will be transported by rotary wing aircraft and 10% by fixed wing. Therefore, approximately 800 personnel per week must be transported by, for example, Sikorski S-61 helicopters operating about 8 daily return flights seven days a week. In addition, the transport of approximately 100 individuals per week by fixed wing aircraft to onshore sites will require at least 7 flights by Twin Otters. If the overland pipeline is under construction, additional personnel movements will be required.

For the levels of activity anticipated in the Region by 1986, approximately 200 ha of land will be required for the primary support facilities. This will provide space for storage of consumables and fuel, accommodation, marine repair facilities and airports. Additional land will be required for access allowance and internal roadways. The two existing major support bases, namely Tuktoyaktuk and McKinley Bay, support (in 1981) operations approximately 20% of the size of those planned for 1986, using approximately 40 ha of land. Therefore, expansion of support bases by approximately 160 ha is required by 1986. This could be provided by expansion of existing facilities, establishment of an additional support base, or a combination of both courses of action. With due consideration given to the extent to which Tuktoyaktuk and McKinley Bay can be expanded, it is apparent that an additional major port and supply centre may be necessary.

Factors to be considered in selecting a primary support base include the following:

1. Good deep sea access;

2. Proximity to the development areas;

3. Good access from the Mackenzie River system;

4. Capability to receive medium to long-range heavy aircraft;

5. Potential overland access by winter or permanent road;

6. Capability to fuel and service all types of marine traffic on a year-round basis;

7. Adequate areas for large dock, storage, and lay-up areas plus associated workshops, accommodation and support facilities;

8. Capability to handle deep draft vessels and drilling systems and aircraft larger than the jets in use in 1981 (aircraft of the size and economy of the Boeing 767 may operate regularly to northern locations well before 1986).

Three or more primary support bases have been assumed for the purposes of this statement and are described below.

5.3.1.1 Tuktoyaktuk

To date Tuktoyaktuk has been the primary support and supply centre for exploration in the Region. Future expansion of support base facilities will be influenced by the wishes of the community. Projected expansion to 1986 is expected to include additional accommodation facilities and expansion of shops, warehouses and fuel storage facilities. The combined support bases are projected to encompass about 100 hectares including roads, access allowance and air facilities. Tuktoyaktuk will also continue to provide supplies and support to onshore exploration and development activities in the area and will serve construction and production activities. The personnel directly related to oil activities is projected to approach 1,000 by 1985. Plates 5.3-1 and 5.3-2 show the support base facilities at Tuktoyaktuk in 1981. Currently Gulf is building their support base, which is expected to house 200 personnel when completed.

5.3.1.2 McKinley Bay

During the first three years of operation in the Beaufort, Dome's drillships were anchored through the winter at natural harbour sites located at Herschel Island and at Cape Parry. This posed various operational difficulties for the company and in 1979 Dome received permission to create a new winter anchorage at McKinley Bay on the Tuktoyaktuk Peninsula. A large cutter suction dredge known as the AQUARIUS was brought in, and by the end of the 1979 open water season, had dredged a navigation channel and basin in McKinley Bay.

The McKinley Bay support base has been created by constructing an island within McKinley Bay approximately 2.5 kilometres from the natural shoreline. A medium draft mooring basin (enlarged to 1 square kilometre in 1981) and access channel were dredged within the bay providing material for the island construction. The island, which serves to protect the ships anchored in the basin, has grown to 63 hectares in size. The mooring basin is utilized for mooring of drillships and other seasonal medium draft vessels (Plate 5.3-3).

Geotechnical studies conducted on the island have shown it to be very adequate as a foundation for future support base facilities. Plans are presently

PLATE 5.3-1 *Bases on shore support the offshore exploration activity. Dome's Tuk Base shown in this photograph accommodates approximately 360 people.*

PLATE 5.3-2 *Esso Resources' support facilities at Tuktoyaktuk. In 1982 the base will be further expanded to accommodate 125 people.*

PLATE 5.3-3 *At McKinley Bay, a mooring basin and access channel have been dredged and an island created. The mooring basin is used for winter mooring of drillships and medium draft vessels.*

being developed, in consultation with the Federal Government, to use the island as a major support base to service year-round exploration drilling and the initial production development activities. Subject to development proceeding at the intermediate development rate, by 1986, the McKinley Bay support base will be about 25 hectares in size including a short take-off and landing airstrip. The base will function as a supply and refuelling centre for offshore drilling, a marine maintenance and repair centre, a winter mooring basin and accommodation centre for support service and shorebased marine personnel. Although these plans have not yet been consolidated, it is anticipated that by 1987, island based facilities at McKinley Bay could include accommodation and community services for approximately 500 personnel. The mooring basin would be expanded to approximately 4 square kilometres in order to provide the necessary area for mooring of drillships and supply vessels and for operation of a marine repair and inspection drydock facility, as shown in Figure 5.3-1. By 1986 the dock could be extended to 400 metres in length.

5.3.1.3 Inuvik

Inuvik is foreseen to continue its role as a regional administration, transportation and freight centre. Due to the proximity of Inuvik to future onshore gas and oil fields, it is anticipated that the community will be utilized by the oil industry as a supply and distribution centre for a considerable amount of the support requirements for onshore operations.

By 1986 it is predicted that additional modest sized fuel and material storage facilities will be required at Inuvik along with workshops and support services. Existing community services and utilities will be used to support these activities with an expansion of accommodation, office space and storage areas being possible requirements.

Much of the population growth that is forecast for the Region is expected to occur at inuvik, where the population could grow at an average rate of about 10% per year between 1981 and 2000 (Volume 5, Chapter 8). By 1990, the population of Inuvik could be above 10,000 and it could be in the order of 18,000 to 24,000 by the year 2000.

5.3.1.4 Yukon Coast

Several studies have been undertaken to examine additional support base sites in the Region. Several studies (Arctic Institute of North America, 1973; Canada Department of Public Works, 1973; Advisory Committee on Northern Development, 1977; Dome Petroleum Limited, 1979) have identified the

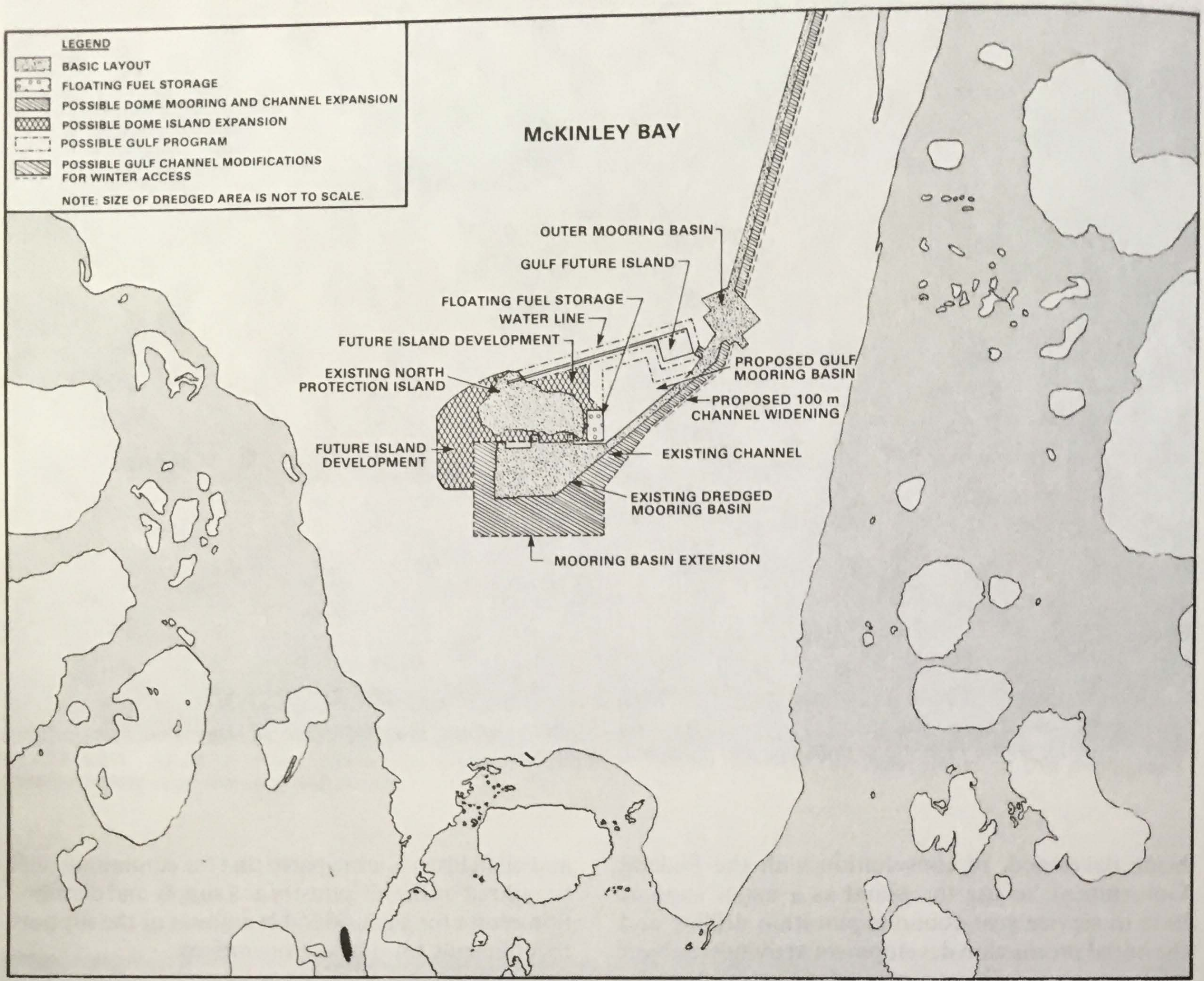

FIGURE 5.3-1 *The McKinley Bay support base will function as a supply and refueling centre for drillships, a marine maintenance and repair facility, a winter mooring basin and accommodation centre. The proposed expansion of the support base up to 1986 is shown here.*

King Point area as a suitable support base site. Also, Gulf are considering Stokes Point an abandoned DEW line installation along the Yukon coast, south-east of Herschel Island. If further support base facilities are required, King Point or Stokes Point would appear to be very likely candidates for such a development. This area has potential for development of a deep water, year-round port, with airstrip capability and excellent civil engineering site conditions, and is relatively close to several offshore development sites. The area is accessible by river barge and could also be reached by winter road and perhaps eventually (Dome proposal) an all-weather road to Fort McPherson and the Dempster Highway, which could be advantageous at some future date.

Assuming the need for such a base exists and the appropriate approvals are obtained, it is estimated that the base may reach a total population of 500 workers by 1986 of whom approximately 150 would work out of the base manning transportation systems and various other mobile operations.

If fully developed, a Yukon coast base may function as the major deep sea port for the Region, providing year-round refuelling and servicing facilities for all types of vessels. Major assembly operations may also be undertaken in the vicinity of the docks. Major installations in the vicinity of the base may include a large floating dock, gravel crushers, a concrete batching plant, and a steel fabricating yard. Figure 5.3-2 shows a conceptual shore base at King Point in 1986.

By 1986, this support base could encompass 75 hectares including road and access allowance and an airport facility capable of receiving Boeing 767 aircraft. Docking facilities could be provided for shallow draft, medium draft and deep draft vessels.

Quarry rock, crushed to various sizes, is required both in the construction of offshore platforms and also within the base. Mount Sedgewick, which is located approximately 53 kilometres south of King Point, is a potential source of rock. It is considered

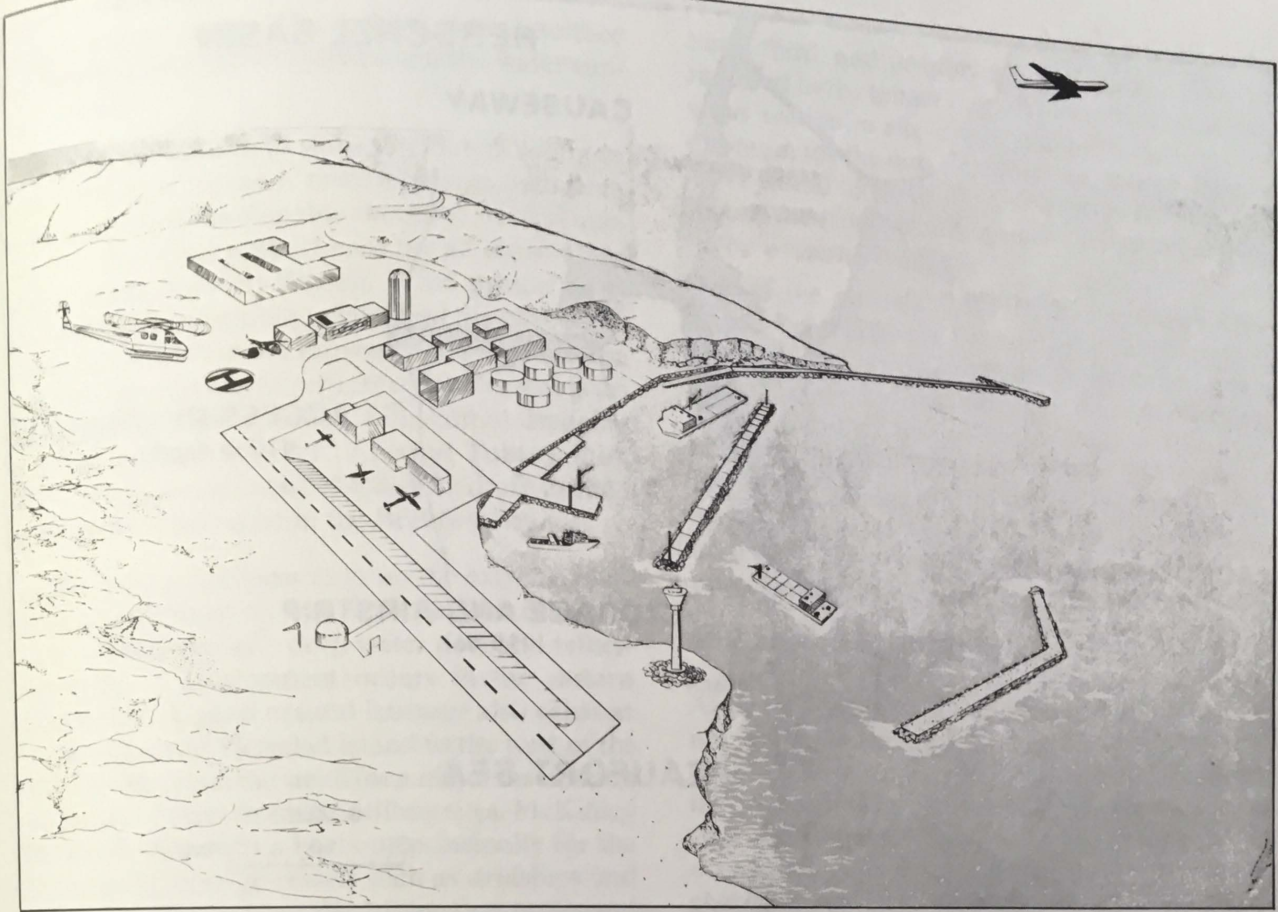

FIGURE 5.3-2 *If further expansion is required for support facilities, King Point is proposed as one of the preferred sites. It has potential for development as a deep water, year-round port and is close to the offshore development sites. Shown here is an artist's rendering of the King Point support base in 1986.*

feasible to transport crushed rock from Mount Sedgewick over an all-weather road to King Point and load it onto marine vessels for transport to the construction locations.

If Stokes Point were selected as the site of a support base, in addition to the deep draft harbour which would be developed, there would be easy access to Herschel Basin. This is a natural deep water basin which could be used to moor the conical drilling unit for supply and maintenance activities.

If approval is given, development of a base at Stokes Point would take place in stages, starting with a small base in 1983 to support exploration drilling. This would entail construction of a causeway and dredging of an access channel and harbour to 10 metres depth. Buildings and a STOL airstrip would also be constructed. A possible design for this development phase is shown in Figure 5.3-3.

In a second phase of development, the causeway might be extended to provide a deep water wharf. A final phase of development could include extension of the harbour to accommodate deeper draft vessels, extension of the airstrip and construction of a wider range of facilities.

5.3.1.5 Other Support Bases

Other support bases including Bar-C, Pullen Island and Swimming Point have been utilized by the oil industry in the Region and have supported exploration activities by providing consumable storage, staging areas, seasonal airstrips and temporary accommodation. It is anticipated that use of advanced staging areas will continue, providing storage space and services to nearby drilling and construction sites. In addition, Wise Bay, Summers Harbour and Pauline Cove have been used from time to time as marine staging areas. This type of activity is expected to continue at these and similar sites. For the most part, these areas will be supported by the major bases at Tuktoyaktuk, McKinley Bay, Inuvik, and a site such as King Point, if required.

5.3.2 COMPONENTS OF SUPPORT BASES

This section provides a more detailed description of support bases by describing the component parts.

5.3.2.1 Harbours

A safe harbour is essential for the various marine vessels which provide supporting service to drilling

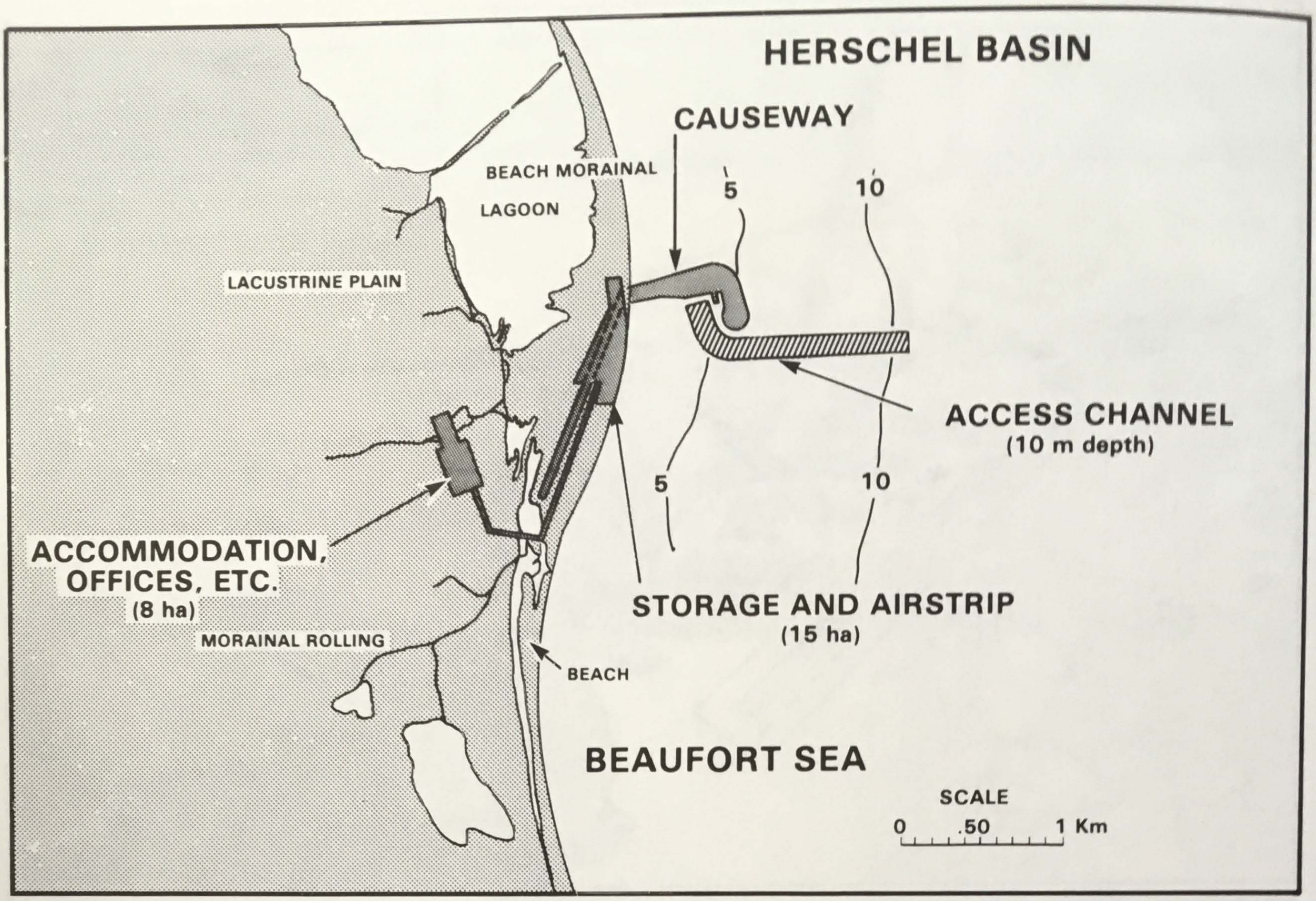

FIGURE 5.3-3 *Stokes Point conceptual first phase development.*

PLATE 5.3-4 *A safe harbour is essential for the various marine vessels which provide supporting service to the drilling and producing systems. Tuktoyaktuk harbour, shown here, is an excellent natural harbour. However, the long shallow entrance channel limits the size of vessels that can come into the harbour. It is also not suitable for year round operations. It is probable that expansion of shore bases to support offshore development will not take place at Tuktoyaktuk but will occur at McKinley Bay, and a site along the Yukon Coast.*

and producing systems. The harbour is the interface between the land support systems and the water support systems.

Tuktoyaktuk Harbour, as shown in Plate 5.3-4, is an excellent natural harbour, relatively large with deep water and a good developable shoreline. It has functioned as the major support base for all exploration drilling in the Beaufort Region. Wind protection is provided by the surrounding land and the harbour is totally protected from ice movements. However, the shallow (4 metre water depth) entrance channel gives limited access to the harbour. Substantial dredging would be required in order to permit Tuktoyaktuk Harbour to accommodate the deeper draft drilling and support vessels used in the Beaufort Sea.

Suitable natural harbours exist on the extreme eastern edge of the Beaufort Sea. Wise Bay, for example, could be developed as a deep water port and refuelling facility if development occurs in the eastern Beaufort Sea. A good natural harbour also exists at Pauline Cove near Herschel Island to the west of the Delta, but the area is too small for a major installation and it is also distant from the drilling sites. McKinley Bay was developed as a harbour principally for the overwintering of large vessels such as drillships and dredges. Plate 5.3-5 shows the drilling fleet and island in McKinley Bay as it appeared in June 1982.

Tuktoyaktuk harbour and McKinley Bay harbour will provide adequate facilities for the next few years but a third, and possibly a fourth, harbour may be required in the longer term. As identified in the previous section, a site on the Yukon coast would be optimum for the next Beaufort Sea harbour. Pauline Cove would likely be used, as it has in the past, as a staging area for exploration and development activity in the western Beaufort.

One of the greatest attributes of the King Point - Stokes Point area is the proximity of suitable quarry rock for offshore construction projects. The area is also one of the few locations in the Region where deep water exists close to shore. In the event that oil or gas were brought to shore from possible future western Beaufort fields for processing and subsequent shipment, the Yukon coast would be suitable and harbour needs could be combined with such an onshore processing facility.

5.3.2.2 Docks and Wharves

Aside from the vessel mooring areas which are largely not visible, docks and wharves are the major harbour facilities. They are used principally by ships unloading and loading cargo. However, other boats, such as tugs and standby vessels, make use of docks on an occasional basis for refuelling, boarding and discharging crew members and passengers, and taking on their own consumables and freight.

The efficient use of docks, as well as concerns to minimize standby time of cargo vessels, has led to

PLATE 5.3-5 *McKinley Bay is relatively near to deep water and required the dredging of a channel and a basin to accommodate drillships which had previously been kept in the Eastern Beaufort; too far from the centre of operations. In the course of dredging the basin and the channel an artificial island adjacent to the mooring basin was built from spoil material.*

advances in cargo handling and storage systems. Pneumatic handling of dry bulk cargo such as barite and cement speeds up the movement of this commodity and also enables the loading and unloading to be done simultaneously with the loading of other cargo. Containerized freight has eliminated the need to handle numerous smaller individual cargo pieces. Containerized cargo handling systems will be used as much as practicable. As well, the use of intermodal containers will minimize cargo handling time. The location and orientation of supplies awaiting transport are also critical factors in providing a functional and efficient cargo handling system. Sufficient dock width will be provided to ensure maximum efficiency.

A key component in determining total dock requirements is the time required to load or offload a tonne of cargo. However, dock requirements will be determined by the pace and nature of development in the Region. For example, if an APLA were used as a harbour and a storage site for materials, it will place some of the materials very close to the area where they will be consumed. This will alter the requirements for supply boats, for support base storage space, and for docks.

5.3.2.3 Airports

Personnel from across Canada travel to the Beaufort Region in fixed wing aircraft and are then transferred to helicopters and STOL aircraft. Conventional jet aircraft like the Boeing 737 require an airstrip 1,700 metres in length (a function of payload and range) whereas the Boeing 767, if employed, will require a runway approximately 2,200 metres in length. Airstrips used exclusively by STOL and other smaller aircraft need be only 775 metres long.

Tuktoyaktuk airport, as it presently exists, is illustrated in Plate 5.3-6. Considerable improvements have been made to this airport during the past three or four years; the airstrip has been lengthened and a new terminal and hangar constructed.

Expansion of airstrips in the Beaufort Sea-Mackenzie Delta Region is likely to include additional lengthening of the strip at Tuktoyaktuk, and construction of STOL strips at McKinley Bay and at all onshore development sites, and possibly STOL strips at each APLA. Provision of a conventional takeoff and landing strip at a Yukon base (should it be developed) could minimize transfer flights and may also provide alternate landing facilities for long range aircraft during inclement weather. Airport facilities will include aprons, ramps and terminal buildings sized to accommodate the type and frequency of aircraft expected. Each airport will require the appropriate navigation aids and control and dispatch procedures and facilities.

PLATE 5.3-6 *Personnel arrive from southern centres on fixed wing aircraft and then transfer to helicopters and STOL aircraft to reach work sites. Tuktoyaktuk airport, where many such transfers are made, is shown here. The Tuk strip was widened and lengthened and special navigation systems added in 1977-78.*

5.3.2.4 Storage and Workshops

One of the primary functions of support bases in the Beaufort Sea - Mackenzie Delta Region has been to provide storage and repair facilities for oil and gas exploration activities. In the future, support bases will provide these services not only for continuing exploration activities but also for the development of oil and gas resources.

It is estimated that, by 1986, approximately 25 hectares will be required at support bases for the storage of materials and equipment. The land area required for this purpose is influenced by a number of factors, the most important being the level of activity and the mode of transportation. As drilling activity increases and hydrocarbon resources are brought into production, there will be a corresponding increase in storage requirements.

During the past years of exploratory operations both on land and offshore in the Beaufort Sea-Mackenzie Delta Region, materials used in drilling operations have been barged down the Mackenzie River. This supply network is reliable although variable water levels in the river do affect the capacity of the tug barge trains. However, this river is only navigable from mid-June until mid-September, thus the supply of consumables for the entire year is moved down the river over this three month period. The deliveries are weighted towards the early part of the season, as inventories depleted in the fall, winter and spring operations are replaced. Due to this limited transport season, there has been a requirement for storing a large amount of equipment and material.

The very nature of the operations in the area requires a tremendous variety of material and equipment. While much of this can be stored outside, some items must be stored in warehouse buildings and heat is required in some of these. Plates 5.3-7 and 5.3-8 show typical consumables stored at Tuktoyaktuk.

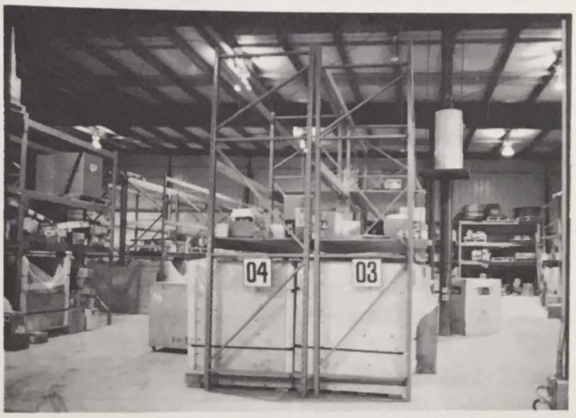

PLATE 5.3-8 *Some consumables required in the Region must be stored in heated warehouses like this one in Tuktoyaktuk.*

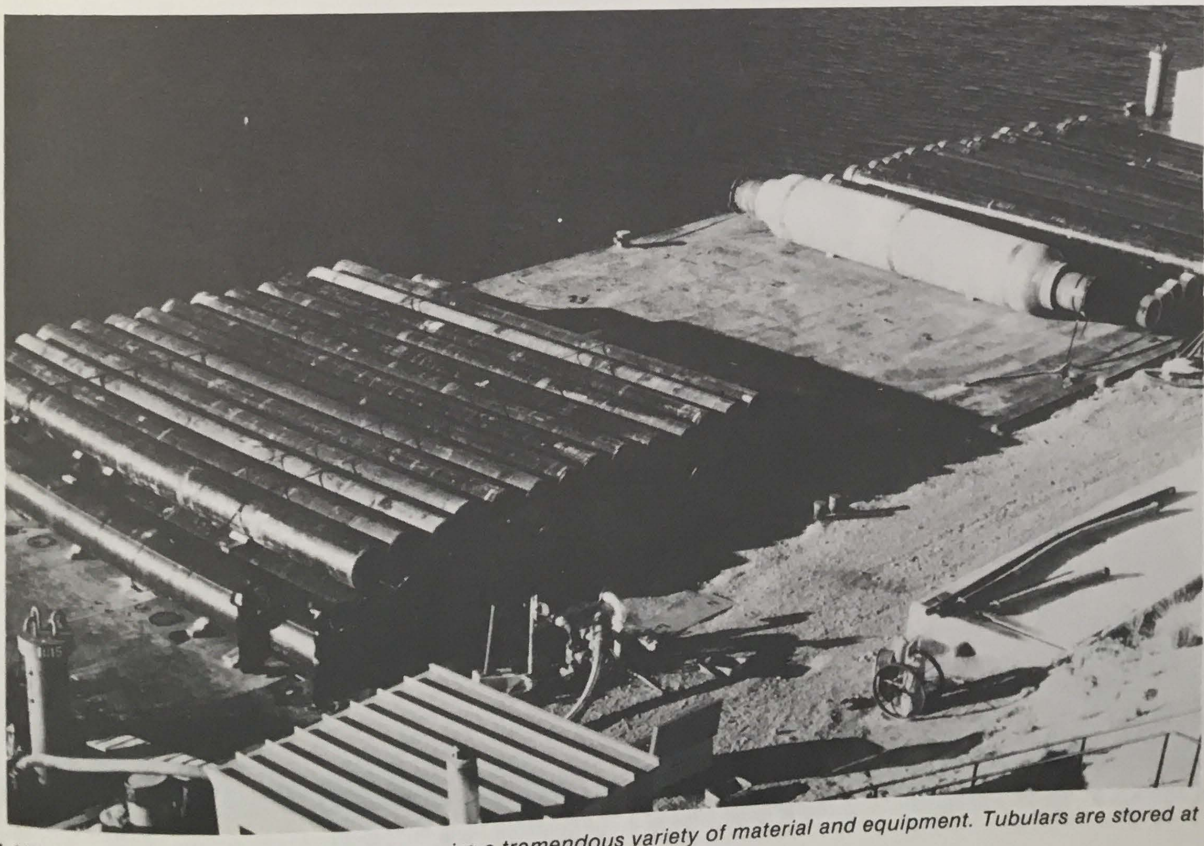

PLATE 5.3-7 *Operations in the Region require a tremendous variety of material and equipment. Tubulars are stored at a Tuktoyaktuk dock awaiting loading.*

As discussed, the location and orientation of consumables in relation to the dock, particularly items which are required frequently and in large quantities, are critical factors in the effective management of cargo. Thus, for example, drill pipe and casing are stored on racks near the dock and are orientated to permit efficient movement. Low turnover items are stored progressively further away from the dock area. Secure storage is provided for items such as pressurized cylinders and hazardous chemicals.

Large amounts of mechanical equipment are also involved in both onland and offshore exploration and producing operations. This equipment has created the need for numerous repair services, garages and workshops. While each activity site will have substantial repair capability of its own, including machine shops, welding shops, and electrical and electronic shops, larger and more sophisticated facilities will be required at the primary support bases in the future. These facilities are also required to maintain land-based equipment such as trucks, buses, loaders, forklifts and cranes. In addition, marine vessel maintenance and repair facilities will be provided at support bases.

5.3.2.5 Liquid Product and Fuel Storage

Fuel requirements in Beaufort Sea—Mackenzie Delta operations are substantial. For example, Dome's operations will consume approximately 75,000 m^3 in 1982 and the industry is projected to use roughly 220,000 m^3 of fuel annually by 1986. Fuel is needed by the marine vessels, regional fixed wing and rotary wing aircraft, support bases, drilling rigs, and return flights of aircraft out of the Region. Fuel consumption will increase in proportion to the level of future activity, even during the production phase when use of natural gas will be maximized. The major existing fuel depots are at Tuktoyaktuk in onshore storage tanks, and at McKinley Bay in floating fuel storage barges (Plate 5.3-10).

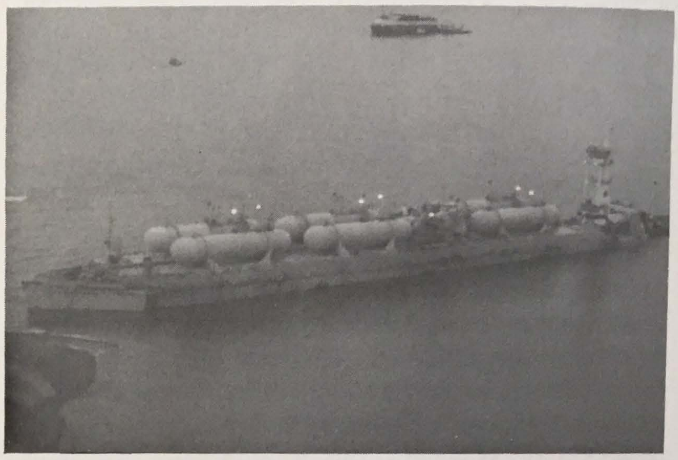

PLATE 5.3-10 *Much of the fuel for offshore operations is stored in floating fuel storage barges.*

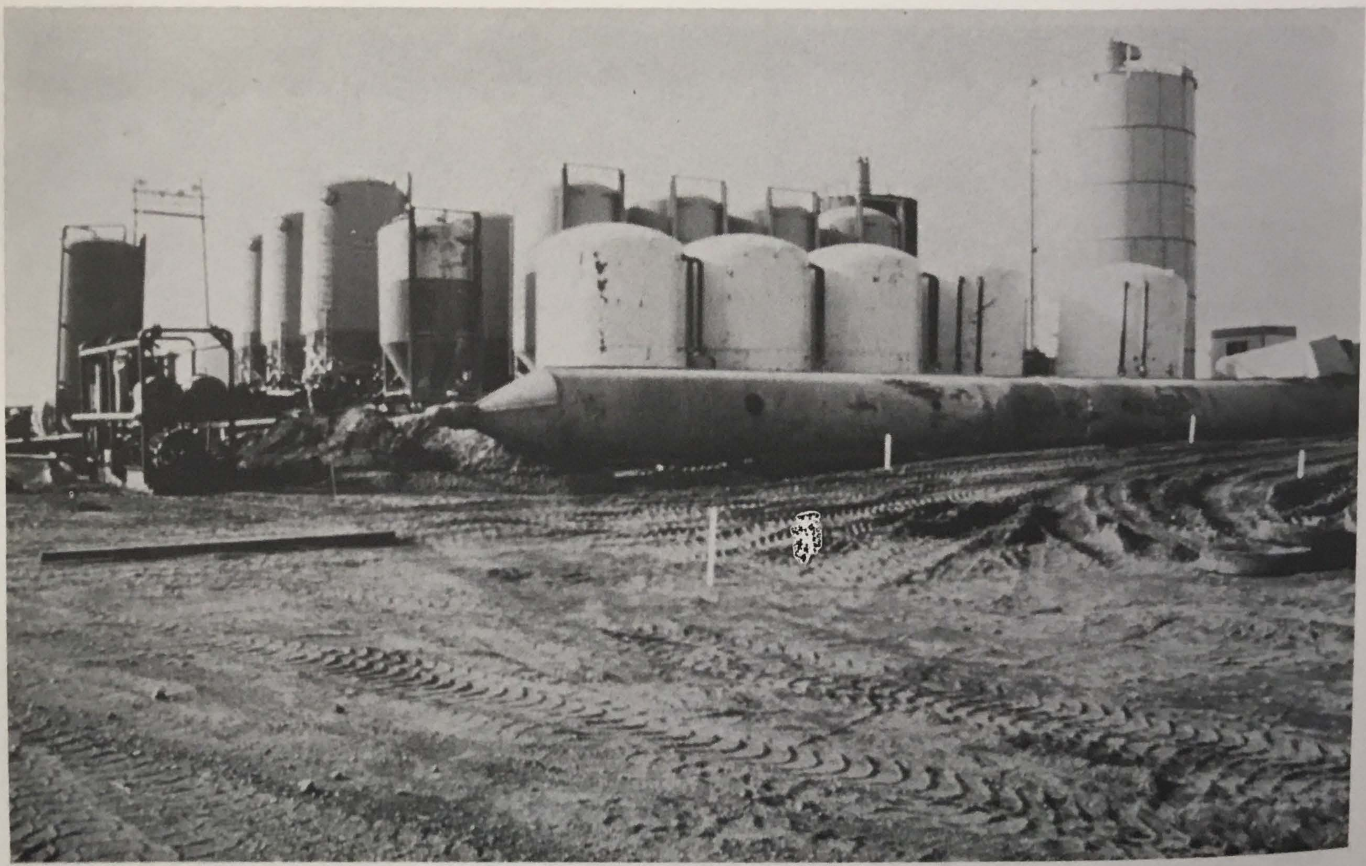

PLATE 5.3-9 *Barite and cement is stored in large silos at a Tuktoyaktuk base for transfer to the supply boats.*

Diesel fuel, aviation fuel, and other refined petroleum products will be stored in large quantities at the support bases. On land, storage tanks are contained within earthen dyked areas sized to contain the fuel stored in the largest tank plus 10% of that contained in all additional storage tanks. Flexible liners, tested under Arctic conditions, will be installed within the tank farm dykes and base to prevent spread of the product in the unlikely event of a tank leak or rupture. Multiple valves on refuelling lines and pipelines designed to close automatically upon loss of pressure, will minimize spillage due to malfunction or human error during refuelling.

Regular fuel inventory balance and inspection and maintenance of storage tanks, pumps and valves are considered the first line of defence to prevent fuel leaks. These will be incorporated into the daily work schedule of fuel management personnel.

As year-round operations are implemented, back-up fuel depots may be required as a contingency measure in the event that the support bases are not accessible because of some extraordinary ice conditions. In 1982, Dome received permission to moor a large double-walled fuel tanker at Wise Bay. Possible future requirements would be similar in that they would be completely portable and readily removed, if no longer needed. The need for such a facility, however, would decrease as offshore APLA's and additional support bases are developed.

5.3.2.6 Navigation Aids and Communications

Many of the aids to navigation for both aircraft and ships require land-based stations. The aircraft systems are relatively simple from a land use point of view, though sophisticated in their operation. They are always located in the vicinity of the airports. The type of systems in use in the north now include microwave landing systems which are located adjacent to the airstrip and the DME (distance measuring equipment) which is located about 300 metres from the end of the runway.

At McKinley Bay a mini-ranger network which uses radar towers onshore is used for precise navigation. However, additional land-based systems would be required to assist future icebreaking Arctic tankers in navigating the Northwest Passage. Navigation systems are described in Section 5.4, and those pertaining to Arctic tankers in particular are described in Chapter 6.

Good communication is essential for the type of operations being carried out on land and offshore in the Region. The types of communications currently in use include: voice communication, telex, facsimile and data transmission.

In the Beaufort Sea offshore operations, the link from land to offshore is provided by VHF radio. Because of the wide area covered by Beaufort Sea-Mackenzie Delta operations it is necessary to have repeater stations along the coast. Three of these stations are located at Garry Island, Pullen Island and Atertak. Plate 5.3-11 is a photograph of a repeater station in the Region. These stations in turn receive their signals from the communications centre at Tuktoyaktuk by microwave. At Tuktoyaktuk the privately owned systems are linked with the public network, Northwest Tel. The public system uses microwave links down the Mackenzie Valley to other public networks in the south. Communication systems are described in more detail in Section 5.4.

In the longer term the oil industry will be able to make greater use of satellite communication devices. These are already used in many land based operations in the Arctic. Their current use offshore is limited because the onsite equipment cannot maintain a proper focus unless it is stationary. This can be achieved on an offshore island but has not been achieved satisfactorily from a drillship, which is constantly in motion. Since in future most year-round facilities in the Beaufort Sea will be islands or some sort of bottom-founded structure, satellite communications will be used more extensively.

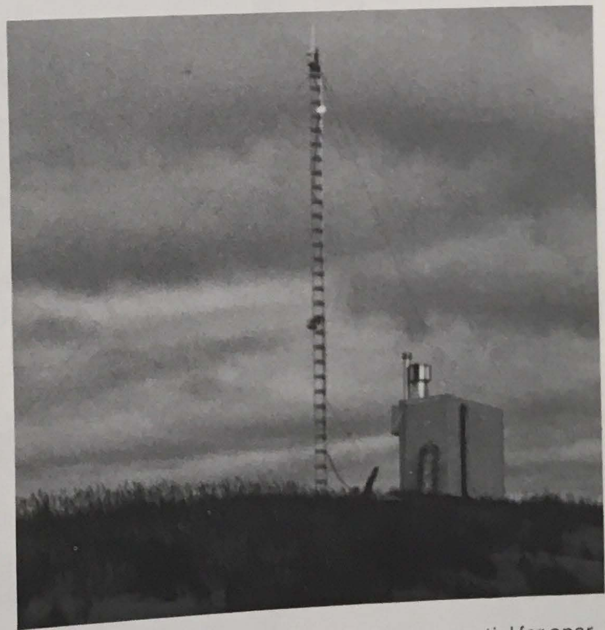

PLATE 5.3-11 *Communication links are essential for operations in the Beaufort Sea-Mackenzie Delta Region. The link from land to offshore is provided by VHF radio using VHF repeater stations as shown here. Direct dial telephone service is available to the drillships.*

Nonetheless, VHF radio links will always be required so existing ground stations are permanent fixtures. There is a possibility that a few more of these stations may be required across the Beaufort Sea - Mackenzie Delta Region and perhaps into the High Arctic as another means of communicating with tankers.

5.3.2.7 Physical Plant

Power generation and heating requirements for the support bases are provided by a physical plant facility. Diesel fuel will be used to power turbines to meet the electrical requirements of the support bases. The physical plant facilities will typically be located nearby the accommodation/office complex (see Plate 5.3-12) and will include power generation facilities, water and sewage treatment plants and distribution pumps, and a solid waste incinerator.

5.3.2.8 Accommodation

Each isolated land location with a continuous presence of operating personnel requires onsite housing. Camp complexes have become relatively standard in remote areas and include sleeping accommodations, galley, dining room and recreation facilities. The size of the camp and the type of facilities provided will vary in accordance with the number of people accommodated, the 'permanence' of the operation and the nature of the work being performed. Plates 5.3-12, 5.3-13 and 5.3-14 illustrate the external appearance and some of the internal features of Dome's Tuktoyaktuk support base.

Recreational facilities at support bases are essential components which provide a variety of options for the personnel during their free time. Most of these will be indoor facilities. For example, Dome's support base at Tuktoyaktuk includes facilities such as racquetball, basketball and badminton courts, exercise room, library and reading room, stereo room, lecture and movie theatre and card room, as well as several television rooms. During the summer months at Tuktoyaktuk, community facilities such as the golf course, baseball diamond and soccer field are used by base staff. Conversely, the local community is permitted limited access to the recreational facilities within the support base. Additional land area will be required for outdoor recreational facilities at each major support base.

PLATE 5.3-12 *Accommodation facilities in this region include both small mobile camps and large permanent facilities such as this camp at Tuktoyaktuk.*

PLATE 5.3-13 *Dining facilities at a Tuktoyaktuk base camp. First class meals are served at all locations.*

PLATE 5.3-14 *At larger permanent camps such as at Tuktoyaktuk, recreation facilities are provided.*

5.3.2.9 Administrative Offices

At drilling and production field sites, only those personnel required to operate and supervise the day-to-day operation will be present. This is usually true for both offshore and onshore operations. The coordination of support services, the logistics of materials handling, employee relations, accounting, engineering and laboratory services and the overall management of an area are handled from an area office at a support base, usually contained within or adjacent to the accommodation facility.

The functions of industry's support bases at Tuktoyaktuk include the following: materials warehousing, storage, control and handling, cost control, communications centre, community and northern interface, employee relations and training, safety, security, personnel transportation control, laboratory service, contractor services, project management, and hotel services.

As activities increase, there will be some expansion of administrative facilities. Oil and gas production activities will introduce a new dimension to the administrative requirements as this is an activity that is not presently being carried out. This will require additional account and communications functions, engineering and laboratory services and another category of management personnel.

The size and location of administrative offices will be affected by the size, number and nature of harbours and support bases that are used in the offshore and onshore operations. If the support base requirements are divided among several locations such as Tuktoyaktuk, McKinley Bay, King Point and one or more APLAs, then the administrative services will be similarly divided.

In addition to area offices there is a need for a district office. District office functions include the supervision of several area or field offices and are responsible for long range planning, budgeting, industry and government liaison, oil and gas reservoir management and production accounting. Personnel usually include a heavy compliment of technical and professional people. The probable location of district offices for each of the oil companies operating in the Beaufort Sea - Mackenzie Delta Region is Inuvik. Personnel posted to the district office could be on permanent assignment so their families would also be resident in Inuvik and the office would be operated on a conventional schedule. Inuvik is a desirable location for district offices because the community can accommodate families and is close enough to the field offices for good communication and access. It also offers good communications and transportation links to Calgary and Edmonton.

District office size is dependent to some extent on the scale of operations in the area office. A usual office compliment would, however, vary from 50 to 200 people over the forecast period. Several companies could be expected to have this size of district office in Inuvik.

5.3.2.10 Waste Disposal Facilities

Sewage generated in accommodation, office, kitchen, dining and work locations at support bases will be treated as required. Effluent, meeting regulatory limits, will be discharged to the Beaufort Sea.

Solid waste generated at support bases and delivered from remote work locations will be incinerated. Incinerator ash and non-combustible solid waste will be deposited in approved landfill sites located near the support bases.

5.3.3 CONSTRUCTION CAMPS

During construction of Beaufort Sea development systems, temporary accommodation and related facilities will be required at locations remote from main support bases. These construction camps will provide accommodation, services, and a base of operation for advanced survey and geotechnical personnel, manpower required for the installation of subsea pipelines, onland gathering systems, an overland pipeline, production facilities, and gravel pits or rock quarry operations.

A typical construction camp will be a self-contained facility with modular accommodation and service units, a domestic water treatment facility using nearby watercourses as a supply, physical plant for power generation and heating, a sewage treatment plant and solid waste incinerator. In some cases the accommodation modules and ancillary facilities will be barge mounted in order to provide mobility and to limit land disturbances.

Staging areas for storage and assembly of equipment will be required at most construction camps. For example, the construction camp for subsea pipelines will require a level area for pipe storage on racks as well as an area for assembly of flowline strings. Temporary docking facilities, sized to accommodate barges or other vessels, will be provided at coastal and riverside construction camps.

Land use will be minimized at construction camps and, where possible, existing clearings and access routes will be used. Working pads, on which facilities will be erected, will be constructed, where necessary, with insulation such as gravel to avoid thawing of permafrost and to minimize disturbance. Snow roads will be constructed to move camp modules and

equipment to locations remote from river or sea access.

Temporary short take-off and landing strips will be provided at most construction camps to transport men and essential supplies such as foodstuffs. Alternately, a helipad could be constructed at smaller or short term construction camps.

When construction is complete, abandonment of the construction camp will include:

1. Removal of accommodation modules, equipment and vehicles;

2. Removal of gravel pads if economically feasible for use elsewhere;

3. Provision of a final cover over buried noncombustible wastes;

4. Reclamation and revegetation of the site to restore equilibrium.

5.3.4 ROADS

For exploration activities in the Beaufort Sea-Mackenzie Delta Region, supplies and equipment have been brought in by barge down the Mackenzie River or through the Bering Strait, by road over the Dempster Highway from the Yukon or by air (small quantities only). These north-south transportation systems are described in Section 5.6. Some of the materials are barged directly to the site where they are required, but other materials must be forwarded by air or road.

The only permanent road in the Region outside of the communities is the Dempster Highway which terminates at Inuvik. In summer, transport onward must be by river, but in winter an ice road is built to connect Inuvik to Tuktoyaktuk on the coast. In addition companies operating in the area build winter roads to meet their particular needs. These may be either ice roads over river channels or the sea or overland snow roads across the tundra. In the past, networks of 500 kilometres or more of such roads have been built and maintained throughout the winter.

As development moves into the construction and production phase, the level of activity in the Region and transport requirements will increase. Support bases will be developed and roads will be required both within support bases and to connect the bases to, for example, borrow pits and other bases. If King Point were developed, it may be desirable to construct a road to connect it to the Dempster Highway at Fort McPherson on the south end of the Mackenzie Delta. A tentative highway corridor plan, which would link Inuvik with Tuktoyaktuk and King Point is shown in Figure 5.3-4. The building of these roads will be determined by government policies and local community decisions in conjunction with industry requirements. Design details including methods of construction, granular material sources and construction timetable will be formulated if decisions are made to proceed.

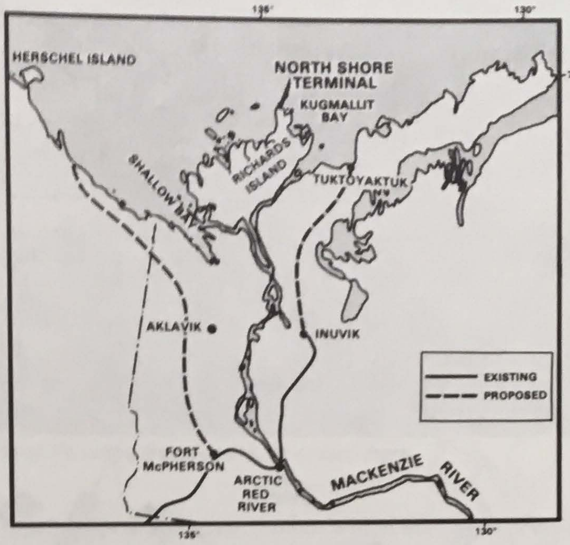

FIGURE 5.3-4 *There are no permanent road facilities serving the oil industry operations in the Mackenzie Delta. A winter road is available from Inuvik to Tuktoyaktuk and the industry has built winter roads over the ice to various locations. Corridors could be provided for future roads which are desireable to support long term production operations.*

As onshore oil and gas fields are brought into production, all-weather roads will be required to link well clusters within a field to the processing plant and to link the plant to borrow pits, the airstrip and a dock on the river system. For example, Figure 5.3-5 shows the probable road network which would be required for development of the Parson's Lake gas field. About 32 kilometres of service roads (3 metres wide) would be needed in this field, together with 2.5 kilometres of transporter road (11 metres wide) designed to carry heavy modules from the dock. These roads would be built of compacted gravel and insulation in order to guard against permafrost thaw.

The road network on the North Slope of Alaska is similar to that which may be expected to develop in the Beaufort Sea-Mackenzie Delta Region. In the Prudhoe Bay field, a small network of local roads connects the production facilities, pipeline stations, housing accommodations, service company complex and the production well drilling pads. These are standard Arctic roads built and maintained by the oil companies and used on a daily basis. Figure 5.3-6 shows the road network in the Prudhoe Bay Field. Plate 5.3-15 is a photograph of a typical Prudhoe Bay roadway. This is the type of road network that would

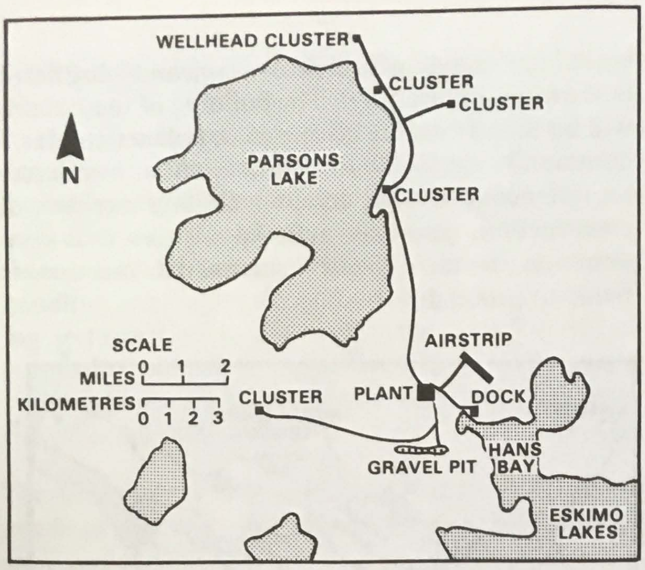

FIGURE 5.3-5 *At onshore oil and gas fields, all weather roads will be required to link well clusters to the processing plant and the processing plant to a gravel pit, airstrip and dock. This is illustrated by the road network likely to be required at the Parsons Lake gas field.*

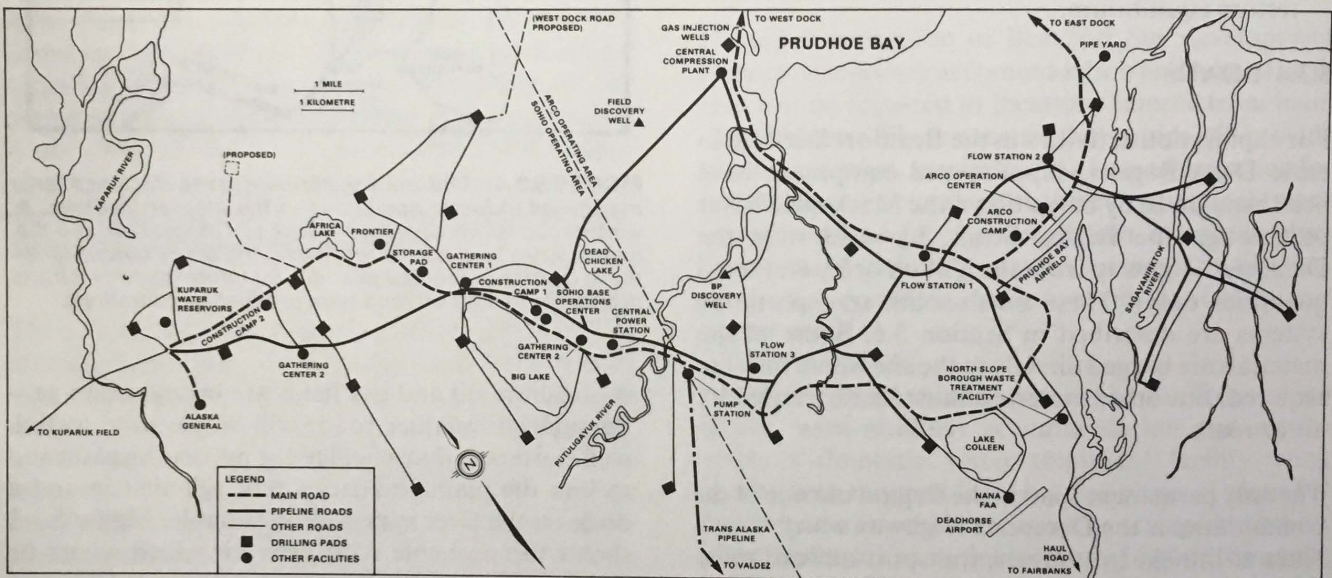

FIGURE 5.3-6 *In the Prudhoe Bay field, as shown, a small network of local roads connects the production facilities, pipeline stations, housing accommodations and wellheads.*

be required for a typical onshore field in the Mackenzie Delta.

If oil or gas are to be transported to southern markets by pipeline, overland access will be required for the construction phase in order to deliver pipe and other material and construction equipment to the pipeline right-of-way. Once the pipeline is in place, only occasional entry is required for pipeline maintenance and repair. In the case of the Alyeska Pipeline from Prudhoe Bay to Valdez, a limited access road has been maintained on the pipeline right-of-way. This road is not available to the public and is not used for any purpose other than inspection of the aboveground sections of the pipeline. If oil and gas are to be transported by Arctic tankers, roads would be limited to those required for support bases and for the development of onshore reservoirs.

The operation in Cook Inlet, Alaska is an example of an onshore production processing facility and a tanker loading terminal where no roads are used. Oil from several producing platforms comes to shore through subsea pipelines for processing. The oil is then delivered from this site by pipeline to the Drift River terminal where tankers are loaded for destinations in the southern United States. There is no road service to either of these locations in either winter or summer and there is no road along the pipeline right-of-way.

5.3.5 POTENTIAL ENVIRONMENTAL DISTURBANCES

This section identifies potential environmental disturbances from support bases, construction camps and roads. Environmental impact is examined in detail in Volume 4.

All components of support bases, from accommodation to power plants and airports, will contribute to some disturbance of either the atmospheric, freshwater, marine or terrestrial environment. There will be atmospheric emissions from power plants, incinerators and other equipment. The marine environment will be affected by dredging activity (for both construction and maintenance) and by discharge of treated liquid wastes into the sea. In the Delta areas, these treated liquid wastes will be discharged to freshwater systems. The terrestrial environment will

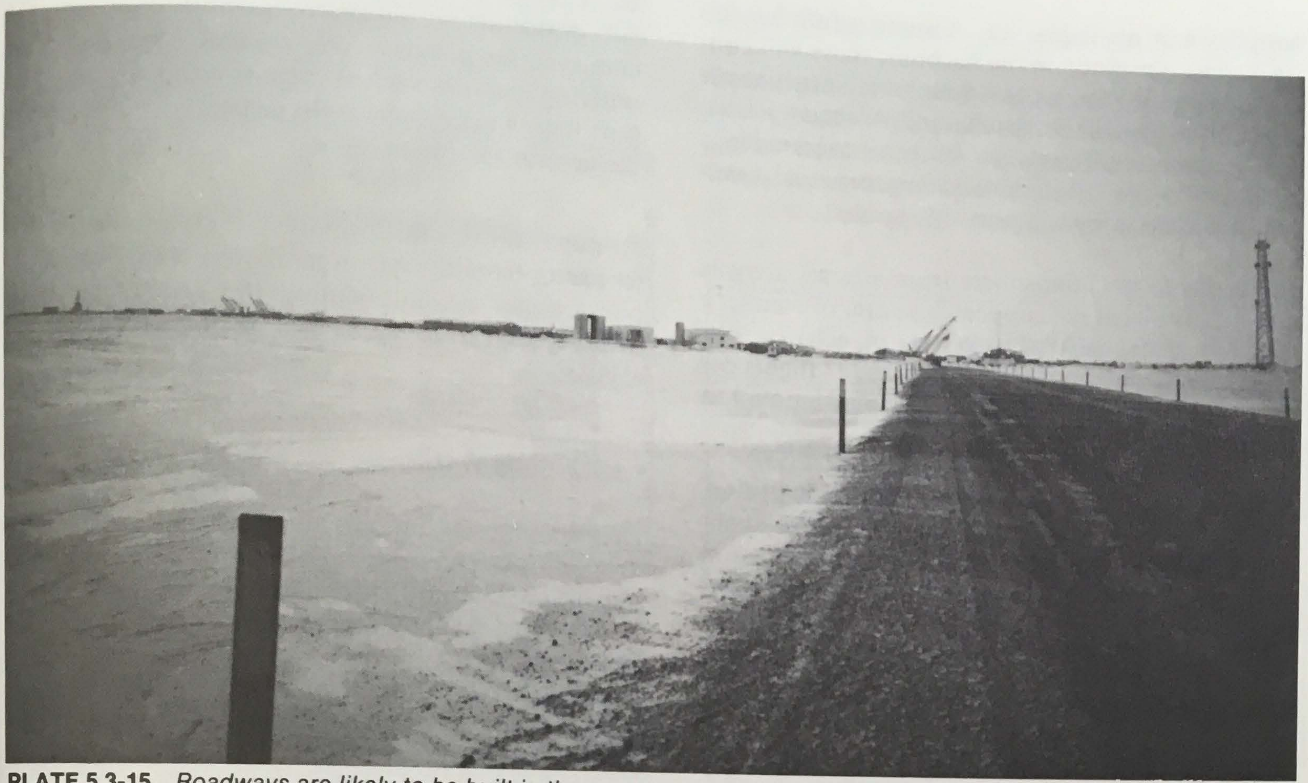

PLATE 5.3-15 *Roadways are likely to be built in the same way as at Prudhoe Bay, Alaska, as shown here.*

be affected by the construction and assembly of buildings (though gravel pads will be used to prevent thawing of permafrost), by land clearing for airstrips, roads and storage areas and by borrow pits and landfills. The disturbances associated with each component of support bases and construction camps can, therefore, be defined with regard to type of land use, the area of land disturbed and the nature of discharges to the air, water or soil.

Most of the disturbances associated with construction camps will be of a temporary and localized nature due to their short lifespan (usually less than two years). The only exception will be reclamation and revegetation procedures which will require time to return the landscape close to its original state.

Land areas required for specific components of support bases have been given in the preceding discussion. These will, of course, depend on the nature and pace of development in the Region and, in the case of construction camps, will vary with the specific work undertaken. At a typical 100 man construction camp, for example, 1 hectare would be required for accommodation, 2.5 hectares for a STOL airstrip, 1 hectare for a sanitary landfill and 1 hectare for a staging area. The size of the staging area may in some cases be larger than indicated above. For example, a construction camp which is used as a base of operation for subsea pipeline installation may require an additional area of approximately 6 hectares for the fabrication of pipe strings.

Sources of disturbance and estimated volumes of discharges to the environment which may be expected at support bases and construction camps are described in the following sections.

5.3.5.1 Atmospheric Emissions

Emissions to the atmosphere from support bases and construction camps will include emissions from diesel fired power plants, incinerators and internal combustion engines. Products of combustion from diesel fuel will include carbon monoxide, carbon dioxide, nitrous oxides, water vapour, hydrocarbons and particulates. It is estimated that at support bases 460 tonnes of emissions per year may be emitted from utilities and heating (Monenco, 1979). At construction camps, power plant emissions may range from 15 tonnes per year to 170 tonnes per year depending on the needs of a particular camp.

Incineration of approximately 3,600 kg of combustible solid waste each day at a support base will contribute to an annual emission of 12 tonnes of particulates, nitrous oxides, water vapour and other components (Monenco, 1979). Incineration of these wastes at construction camps (including an additional 25% estimated for packaging) will result in emissions of 0.5 to 6 tonnes per year.

Any heavy equipment operating at the bases will add to total emissions. At coastal support bases there will be such equipment operating on docks and this has been estimated to generate up to 10 tonnes of atmospheric emissions annually (Monenco, 1979). There will also be marine vessels in the harbour moving

supplies and managing ice. Assuming four vessels operating constantly in the harbour, these will contribute up to 365 tonnes of atmospheric emissions per year (Monenco, 1979; Bercha and Associates Ltd., 1979). However, vessels are likely to use auxiliary generators while in harbour and thus the actual quantity of air emissions will probably be less.

Emissions to the atmosphere from aircraft arrivals and departures at the support base are, of course, a function of engine type and level of activity. For example, the emissions from 5 Boeing 737 flights per day and 10 daily Twin Otter flights would amount to about 80 tonnes per year.

Additional emissions to the atmosphere will include vehicular emission and road dust during the construction stage. Emissions are, of course, a function of frequency of travel, length of trip and emissions per vehicle.

5.3.5.2 Sewage Effluent

Sewage generated from the living, dining and laundry facilities at support bases and construction camps will be treated to regulatory standards prior to discharge to the Beaufort Sea, or to water-courses near construction camps. Treatment plants at construction camps will be modular and will permit capacity fluctuations while retaining treatment efficiency.

Sewage flows will be a function of the number of personnel as shown graphically in Figure 5.3-7.

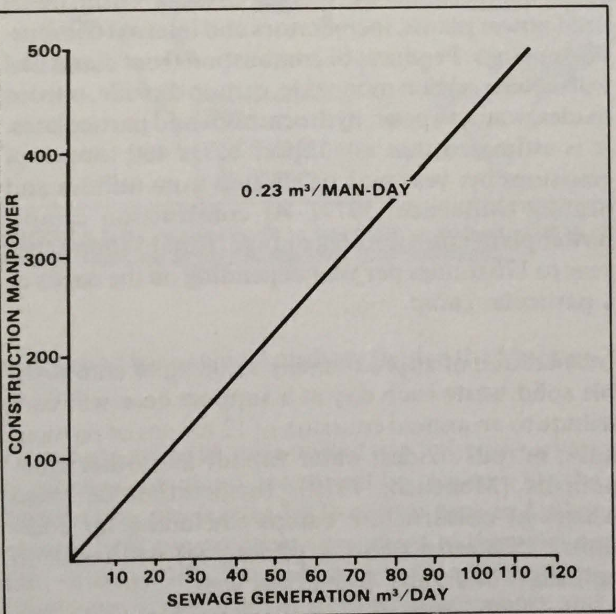

FIGURE 5.3-7 *Sewage treated at support bases and construction camps will be treated to regulatory treatment standards prior to discharge. The volumes of sewage generated will be a function of the number of personnel.*

For example, a major support base accommodating 500 personnel would discharge approximately 115 cubic metres per day. Waste water generated from outlying facilities such as airport terminals and support base workshops would generally be directed to the central treatment plant.

At most construction camps, sewage will be limited to wastes from the accommodation unit. For example, a camp accommodating 100 personnel would discharge up to 23 cubic metres of treated effluent each day.

5.3.5.3 Solid Waste

The accommodation unit at support bases and construction camps is the major source of solid waste generation. Quantities are a function of the number of personnel as shown graphically in Figure 5.3-8. The combustible portion of the solid waste (estimated at 86%) will be incinerated with the residue and other non-combustible wastes deposited in approved landfill sites.

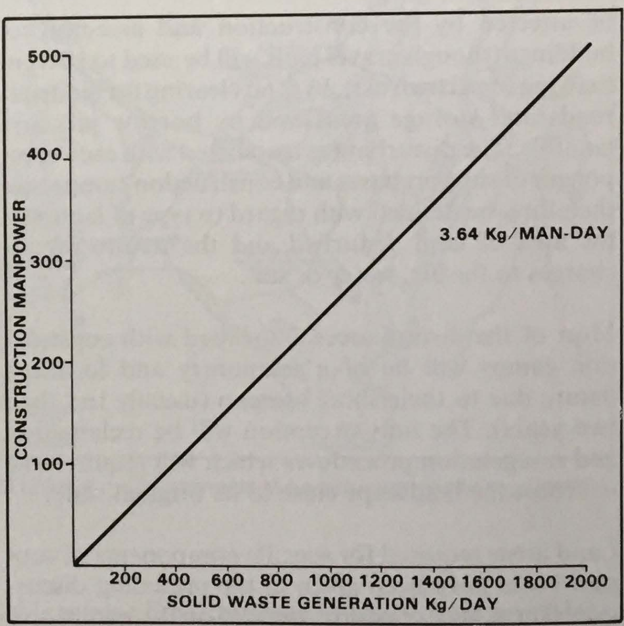

FIGURE 5.3-8 *At support bases and construction camps, combustible solid waste will be incinerated and non-combustible wastes deposited in approved landfill sites. Quantities of wastes generated will be a function of the number of personnel.*

The other components of support bases will also generate solid waste, mostly related to the packaging of equipment and consumables. As well, marine vessels may add to the total solid waste by delivering to the support bases, waste generated on board or from offshore drilling or construction sites. Estimated

supplies and managing ice. Assuming four vessels operating constantly in the harbour, these will contribute up to 365 tonnes of atmospheric emissions per year (Monenco, 1979; Bercha and Associates Ltd., 1979). However, vessels are likely to use auxiliary generators while in harbour and thus the actual quantity of air emissions will probably be less.

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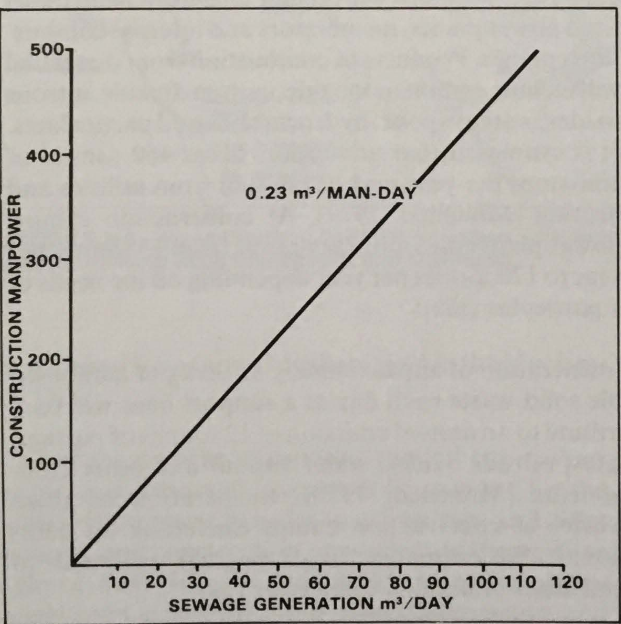

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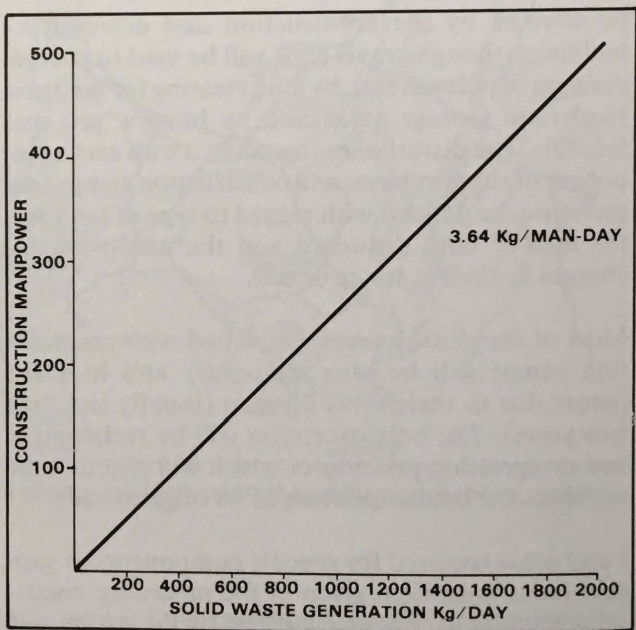

FIGURE 5.3-8 *At support bases and construction camps, combustible solid waste will be incinerated and non-combustible wastes deposited in approved landfill sites. Quantities of wastes generated will be a function of the number of personnel.*

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daily solid waste generation at a major support base housing 500 personnel is summarized in Table 5.3-2.

TABLE 5.3-2

SOLID WASTE GENERATION

Accommodation	=	1820 kg
Bulk Storage/Staging	=	1500 kg
Warehousing Shops	=	420 kg
Airport	=	360 kg
Dock	=	50 kg
Estimated Daily Solid Waste Production	=	4150 kg

For example, at a construction camp housing 100 personnel, solid waste from food preparation and the accommodation unit will be about 360 kilograms each day.

Packaging of equipment and construction supplies will add to this total; however, the amount will be a function of the nature of the camp. The majority of the packaging waste will be combustible and will affect the sizing of the incinerator to a greater extent than the sizing of the landfill site.

Each major support base will have a landfill site nearby for approved disposal of noncombustible solid waste. The landfill will be located and operated in accordance with regulatory requirements. Site conditions, size and duration of construction camps will determine where a landfill will be constructed. If a landfill is not provided, the non-combustible portion of the solid waste wil be stored on site prior to transport to a major support base for disposal. Sewage sludge which may be periodically removed from the sewage treatment plants will be added to the solid waste stream.

5.3.5.4 Heat

Heat is added to the environment with atmospheric emissions and with effluents discharged to the freshwater or marine environments. For example, discharging of cooling water, bilge water and sewage effluent from a dredge operating in the harbour (approximately 16,000 cubic metres per day) will represent a heat discharge of 140 gigajoules per hour. Other vessels in the harbour may contribute an additional 250 gigajoules per hour. Heat quantities from the support base sewage effluent and water treatment effluent are estimated to be 0.4 gigajoules per hour.

5.3.5.5 Noise

Continuous noise will result from the operation of power plants while most other activities will result in intermittent noise, for example aircraft, dredges and heavy equipment. Noise levels for the various components of a support base are summarized in Table 5.3-3.

TABLE 5.3-3

ESTIMATED NOISE LEVELS

Accommodation and physical plant	72-80 dBA @ 20 m
Dredge - continuous operation	65 dBA @ 4 m
Airport	110 dBA
Roadway	85 dBA
Borrow pit	80-115 dBA
Harbour	80-100 dBA
Dock	55 dBA @ 50 m

5.3.5 Roads

The environmental disturbances from the construction and operation of permanent roads in the Region will include land disturbances due to the right-of-way, borrow pits and construction camps, noise and other emission to the atmosphere from vehicles and construction equipment, and alteration of surface water drainage. These, and other factors such as effects on permafrost, wildlife and vegetation will be considered for route selection, roadway design and construction.

5.4 COMMUNICATIONS, NAVIGATION AND ENVIRONMENTAL PREDICTION SYSTEMS

5.4.1 COMMUNICATION SYSTEMS

Reliable communication links are essential to exploration and construction activities in the Beaufort Sea-Mackenzie Delta Region. Support bases must be linked to each other, to southern head offices, to construction and drilling sites (both onshore and offshore) and to marine vessels navigating both within and into the Region. Crews on artificial islands and ships must, in turn, have reliable links with each other.

The communication links serve several purposes. Crews working in each component part of development activities must be able to communicate with each other in order to plan and carry out their work. All these people must then be kept informed of weather and ice conditions in order to minimize the risks involved in these operations, whether marine or on land. Efficient communication links are also vital in the case of emergency when action must be taken quickly.

The Beaufort Sea - Mackenzie Delta Region is connected to the rest of Canada by the Northwest Tel telephone system up the Mackenzie Valley to Tuktoyaktuk. Northwest Tel also operates a mobile telephone system serving the Delta area. Offshore communications are provided by the oil companies themselves each having a communications centre in Tuktoyaktuk.

There is a variety of communication systems in use in the Beaufort Sea-Mackenzie Delta Region and more will be added as the level of activity increases. Each system has particular advantages and disadvantages and thus its own special function.

Microwave systems, combined with VHF radio systems, provide the major communications link for offshore operations both in the Beaufort Sea and other parts of the world. From Tuktoyaktuk, such a microwave relay system extends along the coast and provides a link with crews both onshore or offshore on ships or artificial islands. The microwave system is, however, a line of sight system. For example, the communication link across Canada can be seen from the Trans Canada Highway as a series of microwave towers on the tops of hills and mountains, each being able to receive signals from the previous station and transmit them to the next. The usefulness of this system is thus limited offshore where there are no topographic highs and the line of sight is limited to between 40 and 80 kilometres, depending on the tower height.

The communication link from land to offshore is provided by VHF radio. VHF is also a short range system but is less dependent on line of sight than microwave, having a range of about 120 kilometres. These systems are both inexpensive and reliable and are used for ship to ship, ship to shore, air to ground or ship, and for onshore mobile communications. These are however, low capacity systems. At present two channels to Tuktoyaktuk are available, one for voice communication and the other for data transmission.

As the level of activity increases in the area, the capacity of this system will have to be increased. In addition to the larger number of people needing to communicate, there will be a great increase in the volume of data to be transmitted. This will be comprised, for example, of research data and monitoring information of pipeline flows.

Furthermore, as operations extend further offshore, the VHF systems will not be able to connect to the microwave relay. The microwave relay system will thus be extended along the coast, both east and west, to link all support bases and then will also be extended offshore through relay stations on production islands. It is envisaged that this microwave relay system will eventually form a complete circle. It will then be possible to communicate through the system in either direction around the circle; thus a breakdown at any one point would not disrupt communications.

Short wave and single side band radio systems are used for medium and long range communication, that is, beyond the range of the microwave relay system. The drawback of these systems is that they have a very low capacity, hence the need to extend the microwave system. However, they are universally available, simple to install and operate, reliable and relatively inexpensive.

In the future, extensive use will be made of communications satellites. Satellites will be used for communication between fixed points, that is, head offices in southern Canada, support bases and maybe production islands in the Beaufort Sea-Mackenzie Delta Region. Satellite communication would also be used to link the above locations to Arctic tankers operating through the Northwest Passage. Satellite communication systems are very expensive to set up but they provide the widest areal coverage and have a very high capacity.

The satellite system will form the vital communication link in the proposed Remscan (remote sensing, navigation and communications network) system. This system will not only provide communication links but will also gather and disseminate information on weather and ice conditions and aid in navigation of marine vessels.

The increased level of activity in this Region has given rise to government encouragement to use radio frequencies more efficiently; this could be achieved both by improvements in technology and by using a common carrier rather than private systems. The expense and risk involved in extending systems offshore, however, make it likely that the public carrier, Northwest Tel, will confine their operations to land and a short range ship to shore radio system. Each company operating in the Beaufort Sea-Mackenzie Delta Region will thus continue to operate their own offshore communications systems from individual communications centres (presently in Tuktoyaktuk).

However, the companies will share the radio channels available in the microwave relay system.

In addition to the regular communication links, there will be a special frequency reserved for emergency signals. This 'automatic keying' system will transmit an alarm signal automatically at the turn of a switch to alert other locations to the emergency.

5.4.2 NAVIGATION SYSTEMS

Marine vessels operating in the Beaufort Sea will be equipped with a variety of navigation systems, exceeding those required under the Arctic Waters Pollution Prevention Act. Since each system has its own special advantages and functions, they will compliment each other and, in combination, provide an extremely accurate and reliable navigation system.

The most important navigational aids are position finding systems. Accurate position finding is especially important for navigation in Arctic waters which may be completely covered by ice in winter and infested with hazards such as icebergs in summer. In the case of Arctic tankers operating year-round through the Northwest Passage, accurate information on the ship's position at all times is vital to safe operations.

At present, ships are navigated using satellite positioning systems, when available, radar, dead reckoning and sighting of land features. Of the technical systems available, radar is of primary importance, especially for navigating through the straits and channels of the Arctic Islands. For vessels navigating the Northwest Passage, high cliffs along much of the route give very clear radar images, and from these images the precise distance of a ship from shore is known. It is likely that radar beacons, which both receive and transmit signals, will be installed at key points along the route where accurate positioning is particularly essential, for example at the entrances to Prince of Wales Strait and Lancaster Sound. Radar will continue to be used as a vital navigation aid because of its several advantages: it may be operated from a ship independent of outside support; it is the most accurate short-range position finding system; and it is an economical system.

Radio systems are also used for position finding, from both short to long range. The major system in use world-wide is Loran C and installation of Loran C receivers is required for all ships. This medium to long range system uses shore-based towers equipped with transmitters and a ship's position is fixed by comparing the signals received from several towers of known location. The existing Loran C system covers the north coast of Alaska, extending along the Canadian coastline for some distance, and in the east covers the Labrador Sea. In the future, this system might be extended further into the Canadian Arctic, particularly along the Northwest Passage. However, the existing system will be used for vessels sailing into the Beaufort Sea from the west coast around Alaska, and for proposed Arctic tankers sailing to the east coast.

The Decca navigation system is a medium range system very similar to Loran C. However, this system is not as widely used as Loran C and since it does not presently cover Arctic waters it is not likely to be extended for purposes of Beaufort Sea-Mackenzie Delta development.

By the late 1980's a new navigation satellite (NAVSTAR) is likely to be operational. The Global Positioning system operated with this satellite will be used by all vessels operating within or into the Beaufort Sea and also by aircraft. Vessels will be equipped with satellite receivers used to intercept signals which will be available continuously. These signals will give the latitude and longitude of the ship's position (plus altitude for aircraft) to within 100 metres in real time. The accuracy of this system, coupled with continuous position finding, will be a significant improvement over existing satellite navigation systems which give a ship's position every 30 minutes. Its use will be of major importance in the Arctic where medium to long range radio positioning systems are not available, particularly in the case of proposed Arctic tanker operations. Other navigation systems will continue to be used alongside this system as a back-up and a check.

A short range (about 28 kilometres) radio positioning system already being used in the Beaufort Sea is the Mini Ranger system. This uses two automatically operated shore-based towers transmitting signals which give the exact location of an approaching vessel. It is used for approaches to harbours and for manoeuvring in confined spaces. The location of the ship in relation to the surrounding coastline and harbour features is displayed on a cathode ray tube (CRT) onboard. Plate 5.4-1 shows a CRT display in use on a supply vessel in the Beaufort Sea. In this case, the ship is located in the dredged channel connecting McKinley Bay harbour to the open sea. The overall area is shown on the left hand image, while the larger scale image on the right shows the exact position of the ship within the dredged channel leading to the mooring basin.

The proposed Arctic oil tankers operating between the Mackenzie Delta and an East Coast terminus will be equipped with an array of systems to aid in very short range navigation, that is through ice features in the immediate vicinity of the ship. These systems, including for example forward looking sonars, are discussed in Chapter 6.

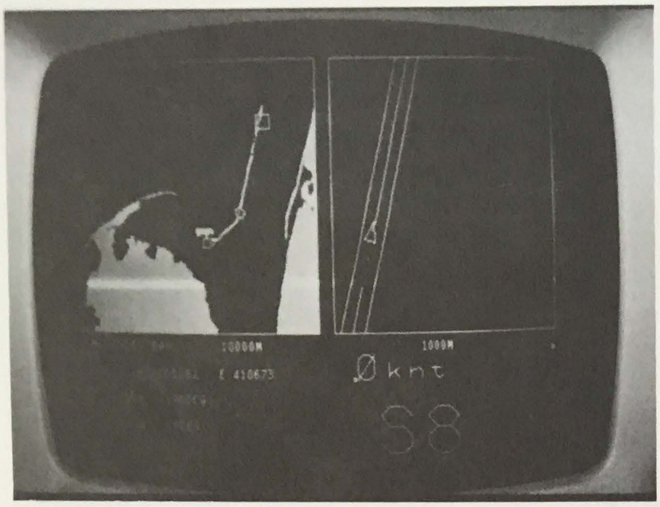

PLATE 5.4-1 *The Mini Ranger radio positioning system is used in the Beaufort Sea for approaching harbours and manoeuvring in confined spaces. In this example, the display screen shows a ship travelling along the dredged channel connecting McKinley bay to the open sea.*

Ships operating in the Region will be equipped with safety systems, including an off-course alarm signal and a collision avoidance system. Radio links between ships will provide further aid to navigation and the exchange of information between vessels will increase the safety of operations.

Traffic management in the Region will be conducted from a shore-based operations centre, forming part of the Remscan system. This will be supplemented by the Canadian Coast Guard vessel traffic management system, NORDREGG. This system is a computerized communications network monitoring ship movements throughout the north from the Canada-Alaska border eastward. It is a voluntary service, similar to the Eastern Canadian Traffic System (ECAREG) in eastern Canadian coastal waters. Ships are requested to provide the Canadian Coast Guard with information on operational or structural defects as well as release of pollutants or damage which could result in pollution. NORDREGG provides ships with information on ice conditions, aids to navigation and icebreaker support. For all Arctic waters north of 60°N including Ungava Bay, Hudson Bay and James Bay, communications with NORDREGG are made through the nearest Coast Guard radio station 24 hours a day.

5.4.3 ENVIRONMENTAL PREDICTION SYSTEMS

5.4.3.1 Existing Systems

A reliable environmental prediction system is essential to operations in the Beaufort Sea-Mackenzie Delta Region. Weather, sea state and ice conditions must be monitored, forecasts made, and the information relayed to all ships and work sites. An efficient system can improve operational efficiency and reduce the risks involved in operating in this area.

The Atmospheric Environment Service has operated the Beaufort Weather Office in Tuktoyaktuk for six years. Data are gathered from meteorological observation stations across the north. A data link from Tuktoyaktuk to the Arctic Weather Centre in Edmonton allows access to information from other High Arctic stations, for example those operated by the USSR. Data from Polex weather buoys are also gathered through this link.

The private companies operating in the Region supplement this information with data they gather themselves: data buoys are deployed to monitor atmospheric pressure and temperature; and regular hourly observations of meteorological and oceanographic conditions are made from ships operating offshore. Ice conditions are also monitored by both airborne and shipborne radar systems and by use of satellite imagery. The advantage of the radar systems is that observations are not dependent on weather conditions.

The Beaufort Weather office uses all this available information to prepare forecasts twice daily. The Arctic Weather Centre also supplies forecasts which are used as a check on Beaufort Weather office forecasts. In addition, the Canadian Meteorological Centre provides long range, large scale forecasts. Ice Central in Ottawa provides 30 day forecasts of ice conditions every 15 days until freeze-up and then they are provided weekly. Short-term ice forecasts are provided by both the Beaufort Weather office and shipboard observers.

5.4.3.2 Future Systems

As hydrocarbon resources in the Beaufort Sea-Mackenzie Delta Region are developed, the level of activity will increase and these activities will be extended further into the winter season and eventually become year-round. In order to safely carry out these activities and to transport oil through the Northwest Passage by Arctic tankers, will require an environmental prediction system which is both more accurate and more efficient. This will be provided by REMSCAN (remote sensing, communications and navigation). This system will gather environmental data from many sources and communicate the information in near real time to a variety of locations. Figure 5.4-1 shows the type of data to be gathered and disseminated and typical data users. REMSCAN will be introduced in stages as the level of activity in the region increases. Highest priority will be given to weather and ice condition forecasts. Most meteorological data can be supplied by the existing system described above, that is through the Canadian

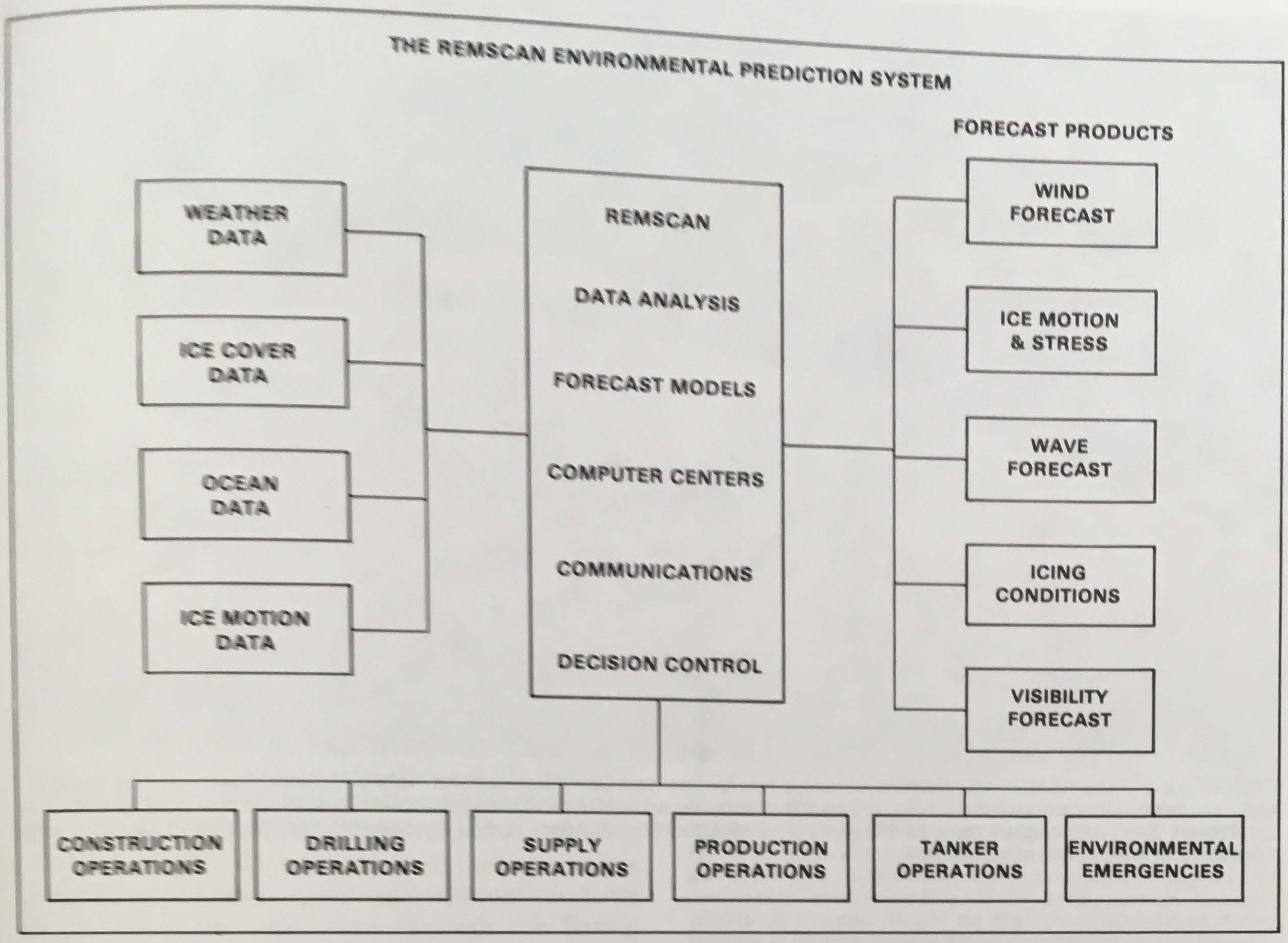

FIGURE 5.4-1 *The REMSCAN environmental prediction system is designed to support the offshore drilling activities.*

Meteorological Centre and the Arctic Weather Centre. The primary data sources for sea ice conditions will be a variety of radar systems. While satellite imagery is already used to provide broad scale ice coverage, the feasibility of developing an all-weather remote sensing satellite is currently being investigated. If developed, this satellite would play a very important role in the REMSCAN system. Until that time, airborne synthetic aperture radar (SAR) will be the primary system used.

A variety of other data will also be communicated through the REMSCAN system. Oceanographic data, for example, will be supplied. This will include information on current velocities, wave heights and frequency and conductivity - temperature profiles. This type of information will be supplied from data buoys and from vessels operating in the area and will then be transmitted to all vessels in the Region.

The crucial role of REMSCAN will be in data communication and management. The system will gather a wide variety of information from many sources, organize it and disseminate it to a multitude of users. This system will operate using a communications satellite. The technology is readily available for voice grade communication through the Anik satellites throughout the area covered by REMSCAN. High data rate communications, however, require a broadband satellite channel. While this is available it is not suited to use on moving structures such as ships or aircraft. In the late 1980's a UHF broadband system may become available which will operate with non-stabilized antennae. Until that time, data gathered from, or information disseminated to ships or aircraft will be transmitted through the communications headquarters for processing (Figure 5.4-2).

5.5 SEARCH AND RESCUE

A search and rescue program has been developed as a joint project by Dome, Esso, Gulf, the Canadian Armed Forces and the Canadian Coast Guard. With facilities centred at the support bases, the search and rescue program uses equipment and suitably trained personnel from the three oil companies. The search and rescue program was designed to provide emergency response to any location within the broad area of interest in the Region with major consideration given to the length of time an individual could be expected to survive under varying conditions. Equipment procurement and program operational designs were formulated with consideration of the geography,

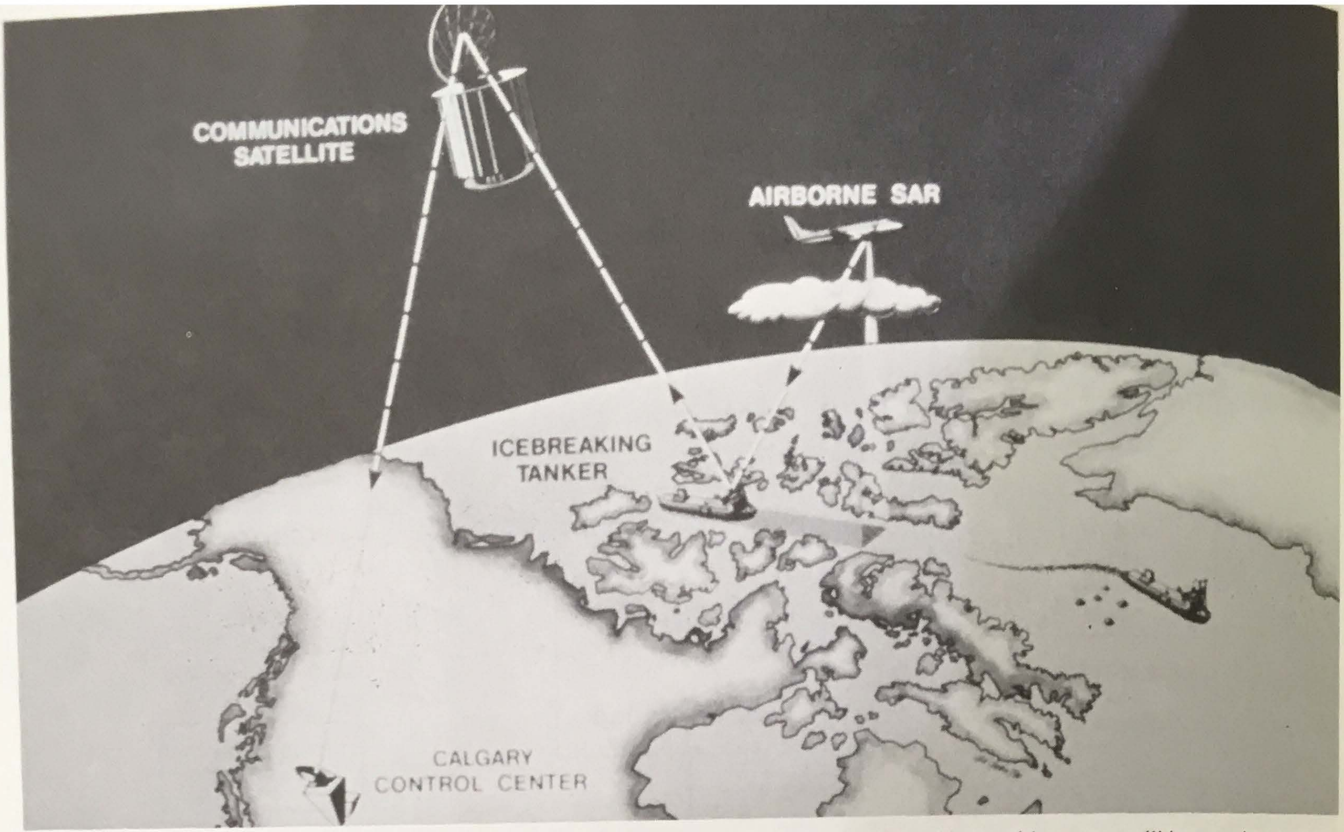

FIGURE 5.4-2 *The REMSCAN (Remote Sensing, Navigation and Communications Network) system will be used to gather and disseminate environmental data and to provide communication links and navigation aids to all ships and activity centres in the Region. Synthetic apeture radar (SAR) and side looking airborne radar (SLAR) are capable of determining ice conditions regardless of weather or cloud cover.*

topography, climate, level of activity, communications equipment, availability and proximity of assistance and medical services.

One of the three oil companies will take the lead role as determined by the nature of the incident. Effective assistance will be provided to any site within the Region within 30 to 90 minutes and will continue until the Canadian Armed Forces arrives on the scene to assume overall responsibility. The procedures developed for search and rescue in the Region have been closely patterned after those employed by the Canadian Armed Forces and Canadian Coast Guard to ensure compatibility.

A broad range of specialized equipment has been provided, or is planned for introduction in 1982. These include helicopter rescue hoists, electronic direction finding equipment, rescue nets, life rafts which may be dropped from aircraft, rescue boat, personal strobe lights, and enhanced communication facilities. General survival training has been provided to all personnel working in the Region. Training for search and rescue personnel, which is continuing, has initially been provided by the Canadian Armed Forces.

Although the probability is very low, there is a minimal risk that personnel working on an artificial island or drillship would have to be evacuated. Detailed evacuation plans have been formulated and provide a graduated response from normal operations to full evacuation. Intermediate levels of response include suspension of drilling operations, sealing of wellbores, and evacuation of non-essential personnel. Evacuation is carried out using the closest available ships or aircraft. Evacuation onto the ice is another option available in extreme circumstances during winter.

During drilling operations, all drillships have a standby vessel in attendance capable of accommodating all personnel. Helicopters can be brought in on short notice and will evacuate personnel to the nearest helideck (such as another drillship, other vessel or artificial island) or to the nearest support base. All drillships, and artificial islands are equipped with safety and survival equipment, and life boats sized to accommodate all personnel with additional space besides as a safety margin.

If a vessel other than a drillship runs into difficulty, evacuation to life boats or to the ice (during winter) would take place. The nearest available marine vessel and helicopter would be routed to the site to lend

assistance. Under normal circumstances, rescue teams would arrive within 45 minutes.

Preventative programs have been implemented to minimize the possibility of emergencies arising. For example, all offshore flights are conducted with twin engine aircraft, with highly trained and experienced aircrew; helicopters are equipped with flotation devices, and all aircraft, marine vessels and other vehicles are equipped with safety and survival equipment in excess of required levels. All aircraft flights in the Region are continuously monitored with respect to condition of flight, location, fuel status and flight progress. In the event of an emergency situation, search and rescue operations will be initiated at a moments notice through the communications network described in Section 5.4.

5.6 NORTH-SOUTH SUPPORT SYSTEMS

Development of oil and gas reservoirs in the Beaufort Sea-Mackenzie Delta Region will entail the transportation of large volumes of cargo to the area and, if an overland pipeline is built, to intermediate points along the route. Heavy equipment will continue to be shipped from the west coast through the Bering Strait, and it is possible that freight may also be delivered by icebreaking tankers returning empty through the Northwest Passage at some future date. However, it is anticipated that expansion of existing north-south routes will handle most of the increase in cargo transported.

Inuvik, as terminus for the Mackenzie River route, has been the primary trans-shipment and resupply centre for the western Arctic for the last decade. It has grown steadily in this role and has also become a centre of local government, air services (both charter and scheduled), and since 1979 has been the terminus for the Dempster Highway.

Tuktoyaktuk has functioned as the major support base in the Region and the majority of barges which carry supplies down the Mackenzie River dock at Tuktoyaktuk. Recently, a support base at McKinley Bay has been established and a portion of the consumables used in the Region are directed to McKinley Bay.

5.6.1 WATER TRANSPORTATION

Access by water to the Beaufort Sea-Mackenzie Delta Region is possible by three routes; the western route through the Bering Strait, the eastern route through the Northwest Passage, and down the Mackenzie River from Hay River (see Figure 5.6-1). The latter is the traditional lifeline to the western Arctic and has

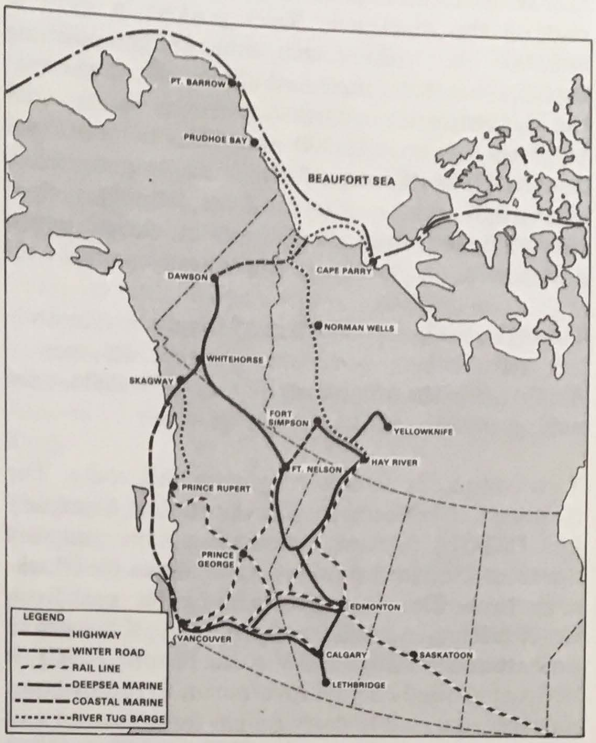

FIGURE 5.6-1 *Freight is moved into the Beaufort Sea-Mackenzie Delta Region by barge down the Mackenzie River, by truck along the Dempster Highway, and by ocean-going barge around Alaska. Some emergency supplies and perishables are moved into the Region by aircraft. The possibility of moving freight on the return voyage of Arctic tankers is another option being considered for the future.*

been the most important and least expensive mode of transport for cargo to date.

For four months of the year, shallow draft barge trains moved by tugs deliver cargo to communities and areas of industrial activity on the river and the Beaufort Sea coast. Such a barge train takes three weeks to complete the round trip from Hay River to Tuktoyaktuk and can deliver up to 5,000 tonnes of cargo.

Hay River, on the southwestern shore of Great Slave Lake is the principal loading terminal for Mackenzie River traffic. Cargoes are delivered to the terminal by truck or by rail from Edmonton and points to the south. Some cargo could be carried along the Mackenzie Highway to Fort Simpson for loading onto barge trains if loading facilities were improved at this location. This route would avoid the river rapids between Fort Simpson and Hay River, since these rapids limit barge payloads. Alternatively, river navigational constraints might be reduced by dredging or other channel improvements such as those proposed by the Federal Department of Public Works.

The early 1970's was the period of most intensive exploration activity to date in the Beaufort Sea-

Mackenzie Delta Region. For this reason, traffic carried on the Mackenzie River peaked in 1972 at 425,000 tonnes. Since that time, freight carrying capacity has been increased somewhat. Currently, the Mackenzie river transport system has the capacity to carry between 500,000 and 600,000 tonnes per annum (Dalcor Group, 1979). Of the freight carried, about half is petroleum products; other principal cargoes include drilling consumables, barite, potash and general supplies for northern communities.

However, while capacity to carry freight by this mode has increased in recent years, actual volumes of freight carried have decreased (approx. 260,000 tonnes were carried in 1979).

Two companies handle freight on this route. The largest is the Northern Transportation Company Ltd. (NTCL), a crown corporation. This company operates a service from Hay River, down the Mackenzie to the Delta and points along the coast from Colville River in Alaska to Spence Bay, Keewatin in the east and to Banks and Victoria Islands. NTCL is licensed by the Federal Government to supply communities and also to carry freight for industrial and commercial enterprises. In 1979, NTCL carried 215,000 tonnes to points along the Mackenzie River and the Arctic Coast. NTCL's vessel inventory is shown in Table 5.6-1.

TABLE 5.6-1

CARGO VESSELS SYSTEM

Type	N.T.C.L.	A.T.L.
Non-powered Barges	166	21
Tugs and Supply ships	31	14
Survey Vessels	2	2

Source: Northern Transportation Company Ltd., 1982
Arctic Transportation Company Ltd., 1982

NTCL owns terminal facilities at the main stages on the Mackenzie River, and uses public landing stages at smaller communities. Table 5.6-2 summarizes the wharf facilities along the route.

Arctic Transportation Company Ltd. (ATL), operates both along the coast and down the Mackenzie River. This company which started operating along the Mackenzie River in 1976, is not licensed to supply communities and thus most of its work is in support of oil companies. In 1981, ATL carried 23,000 tonnes on the Mackenzie River using two barges. However, the largest component of their operation is offshore.

TABLE 5.6-2

WHARF INVENTORY - MACKENZIE RIVER SYSTEM (1981)

Community	Wharf Length m
Hay River	1462
Norman Wells	137
Arctic Red River	Varies
Fort McPherson	61
Aklavik	213
Inuvik	232
Tuktoyaktuk	730

Source: Dome and N.W.T. Govt., 1980

Lasting from mid-June until late October, these operations are based in Tuktoyaktuk. In 1981, ATL started a four year construction program for a terminal in Tuktoyaktuk. The first phase, completed in 1981, consisted of a 200 metre wharf and two new vessels; warehouse and ancillary facilities are also to be built.

5.6.2 AIR TRANSPORTATION

In northern Canada, air is the most important mode of transportation in terms of passengers carried. Due to the extreme climate and nature of the physical environment and lack of roads, it is the only system that can operate year-round. Also,because of the long distances involved, it is the only means of transport that can efficiently move personnel and provide emergency services.

There are five class 'A' airports in the Northwest Territories which serve the route between southern Canada and the Beaufort Sea. These serve as regional centres for feeder services to smaller communities. Yellowknife and Inuvik, in particular, are centres for charter companies which perform an essential role in serving both indigenous communities and the oil and gas industry.

A summary of the airports and airstrips available for use by aircraft importing heavy cargoes into the Beaufort Sea-Mackenzie Delta Region is given in Table 5.6.3.

TABLE 5.6-3

AIRPORT INVENTORY - MACKENZIE/BEAUFORT AREA

Location	Runway (ft.)
Class 'A' Airports	
Inuvik	6000 (asphalt)
Norman Wells	6000 (asphalt)
Yellowknife	7500 (asphalt)
Fort Simpson	6000 (asphalt)
Hay River	6000 (asphalt)
Class 'B' Airports	
Tuktoyaktuk	5000 (gravel)
Fort McPherson	3500 (gravel)

Boeing 737 and Hercules aircraft may land on the sea ice at McKinley Bay. This capability has also been demonstrated at Pauline Cove and Summers Harbour. DEW line airstrips at Komakuk Beach and Cape Parry have been used to service drilling operations and overwintering facilities.

Commercial air freight and air passenger service requirements will increase in proportion to the level of activity in the Beaufort Region. They are also influenced by the diversity of activity and the number of operators, since smaller operations are not conducive to charter air service. At the present time Pacific Western Airlines (PWA) is the largest scheduled air carrier operating from the south to the Mackenzie Valley. A daily service is operated from Calgary and Edmonton to Inuvik and intervening points. PWA operates Boeing 737 aircraft which accommodate 117 passengers or a combination of cargo and passengers. Several companies offer charter services into the Arctic. Due to the high cost of air transportation, cargo services are confined to the supply of emergency and perishable goods, while other modes of transport are used to supply bulk and heavy goods.

It is likely that the frequency of scheduled commercial flights will increase to at least its previous level in the next few years and stabilize. Thus improved air service will be available for all of the residents of the north.

In addition to the commercial aircraft movements, Dome operates a Boeing 737 service carrying both passengers and cargo into Tuktoyaktuk on a daily basis during peak periods. Esso Resources operates Lockheed Electra flights to Inuvik twice per week. In addition, other aircraft such as Hawker Siddeley H.S. 748, de Havilland Twin Otter, and DC-3's are chartered as required by the various companies.

5.6.3 GROUND TRANSPORTATION

The Mackenzie Highway links Alberta and southern Canada to Great Slave Lake and the Mackenzie River (see Figure 5.6-1). It is an all-weather gravel road with the northern terminus near Wrigley. Long term plans exist to extend the road to Fort Good Hope, though this will not be done in the foreseeable future. Speed and load size are restricted by the terrain and road condition; no traffic is possible during freeze-up or thaw when neither ferries nor ice bridges can be used; and the limited present capacity of ferries causes traffic delays at river crossings in summer. The Mackenzie Highway is used to truck freight from Alberta to the barge terminals, principally at Hay River.

The Liard Highway is under construction from Fort Nelson, in southern British Columbia, to Fort Simpson. This is scheduled for completion in 1983 and will provide a shorter route for freight from British Columbia to the Beaufort Sea-Mackenzie Delta Region, with transfer to barges at the Fort Simpson terminal.

Construction of the Dempster Highway, about 675 kilometres long, started in 1959 and was completed in 1979. It is a gravel highway with ferry crossings for summer travel (June to September) and ice bridges in winter (mid-December to mid-April). The highway is closed in the intervening periods of thaw and freeze-up. In winter, an ice road links the Dempster Highway at Inuvik onward to Tuktoyaktuk. Consideration has been given to constructing a permanent road over this route during the 1980's. In summer, freight must be barged or carried by air north from Inuvik.

At present, freight from Vancouver is either shipped to the Region through the Bering Strait or is carried by ship to Skagway, then by the Whitepass and Yukon railway to Whitehorse, and finally by truck along the Dempster Highway to Inuvik. The Dempster Highway is also used by trucks originating in Alberta which reach it by way of the Alaska Highway. The length of these routes, coupled with the transfers between three different modes of transport in some cases, make use of the Dempster Highway alternative very expensive. Thus, for oil companies operating in the Beaufort Region, it is used principally to carry supplies during winter when other routes are impassable. In the future it may also be used to truck barite from northern mines to the Beaufort Region should it be required.

5.6.4 FUTURE TRAFFIC PROJECTIONS

The present maximum capacity of the Mackenzie River barge system by all users from Hay River to the Beaufort Sea is about 600,000 tonnes. If this system were used to the fullest extent it could carry a large

proportion of the cargo forecast for energy industry requirements. Additional freight beyond this would be carried either by road over the Dempster Highway, by air, by expansion of the Mackenzie River system, by Arctic tankers returning to the Region, or by seasonal sealift operations around Point Barrow. The first two alternatives are, however, very expensive. It has been shown, for example, that the cost of moving freight from Edmonton to Inuvik via the Dempster Highway can cost two to three times more than the comparable cost using the Mackenzie River. Air transport, because of the high cost will only be used for the transport of personnel, perishables and urgent supplies.

One factor that is likely to affect the future distribution of cargo between modes of transportation are the changing needs of the oil industry. The introduction of extended season drilling vessels and the increased level of activity in the Region may make summer delivery of supplies by sea and by river impractical. For example, drilling supplies delivered to Inuvik and Tuktoyaktuk at the end of the summer barge season may have to be stored for long periods for winter and spring drilling. The solutions to this problem include expanding storage facilities, to use air transportation, and to use road transportation via the Dempster Highway. Since the capacity of the latter is limited and the second alternative is being used at considerable expense, it can be expected that expansion of storage facilities and of the fleet capacity along the Mackenzie River will be undertaken to handle most of the cargo increase. In the future it is also possible that the summer sea lift season could be extended using ice reinforced vessels especially designed for the purpose.

Several specific issues prove to be of over-riding importance in the consideration of the south-north logistics of moving thousands of people and hundreds of thousands of tonnes of cargo each year.

The Mackenzie River barge system will likely be used to its complete capacity by 1986 and may have to be expanded an additional 20 to 40%, depending upon the extent to which the Dempster Highway route and Point Barrow sea lift transportation options are used in the future. Expansion of the river system will therefore affect points along the system as well as the terminus at each end.

Use of the Dempster Highway route is foreseen to expand considerably in order to relieve the pressure on the other modes of transport as each reaches capacity. Assuming barite is mined in the Yukon, it will be shipped up the Dempster Highway along with shipments of materials from Vancouver which have the least cost differentials, such as cement. Local use of the road is also expected to increase.

A substantial increase in air transport activity is anticipated along the south-north axis as large numbers of personnel are rotated to and from work areas and southern urban centres. Large increases in the number of medium range passenger and cargo aircraft may be anticipated with, for example, several more Boeing 737 aircraft dedicated directly to the oil and gas effort alone. In addition, indirect traffic generated by this increased activity will place additional demands on the regular services required for the established northern communities.

Aircraft larger than the Boeing 737, namely the Boeing 767 are considered a distinct possibility and their use would considerably reduce the requirement for Boeing 737 aircraft.

The use of the civil version of the Boeing Chinook helicopter could radically alter the pattern of offshore personnel transportation since this helicopter has a much greater payload/range capability than the rotary wing aircraft now in use.

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CHAPTER 6 - OIL AND GAS TRANSPORTATION SYSTEMS

Transportation systems are needed to link oil and gas production facilities in the Beaufort Sea-Mackenzie Delta Region to southern markets. There are two main systems under active consideration; icebreaking tankers and overland pipelines. Either transportation system is technically feasible, and it is possible that, eventually, both tankers and pipelines may be used to deliver hydrocarbons from the Region to market. The proponents believe that the environmental and socio-economic impacts of both systems can be maintained within acceptable limits.

6.1 OVERLAND OIL PIPELINE SYSTEM

For well over a decade, industry has been extensively involved in the design and route selection of pipelines that would transport both crude oil and natural gas from the Beaufort Sea -Mackenzie Delta Region to southern markets. Mackenzie Valley Pipeline Research Ltd. was formed in 1969 to study and seek solutions to the problems of designing, building, operating and maintaining a safe, efficient oil pipeline system in the Arctic and sub-Arctic. A pipeline route through Canada was first contemplated to link major oil discoveries on the North Slope of Alaska with Canadian and United States energy markets. A research and engineering assessment program was undertaken to establish technical and environmental feasibility. As part of this research, a full-scale experimental pipeline loop was constructed aboveground near Inuvik, in the Northwest Territories. In addition, a short section of pipe was buried so that the behaviour of thawed permafrost could be observed. As a result of 4 years of effort it was concluded at that time that construction of a large diameter oil pipeline was technically feasible and could be built and operated without major or irreparable damage to the environment.

In 1975, Beaufort-Delta Oil Project Limited was formed by a consortium of oil and pipeline companies to conduct feasibility and design studies necessary to support an application to construct an oil pipeline system from the Mackenzie Delta to Edmonton. Utilizing research carried out by Mackenzie Valley Research Limited and Alyeska, it was concluded that a warm oil pipeline could be constructed down the Mackenzie Valley without causing undue disturbance to the environment along the pipeline route. Interprovincial Pipe Line (NW) Limited, filed an application in 1980 and subsequently received approval to construct a small diameter, buried pipeline for the transmission of crude oil from the Norman Wells oil field to connect with an existing pipeline system in northern Alberta near Zama.

In Alaska, the Trans Alaska Pipeline, stretching some 1,287 kilometres from Prudhoe Bay to Valdez, commenced operation in June, 1977. There are numerous environmental similarities between this system and a Mackenzie Valley pipeline but probably the most important relates to the design and construction in permafrost. Many lessons were learned from this project which will be applicable and beneficial to future energy projects in the Canadian Arctic.

6.1.1 PIPELINE ROUTE

An overland crude oil pipeline would likely originate at a location near North Point on Richard's Island at the northern end of the Mackenzie Delta. It would extend approximately 2,250 kilometres to a southern terminal near Edmonton, Alberta (see Figure 6.1-1). A pipeline with an outside diameter of 1,067 millimetres would be required to satisfy the high production scenario. For lower production scenarios, smaller diameter lines could be utilized, however, the route, design and construction criteria developed for the 1,067 millimetre warm oil pipeline would be similar.

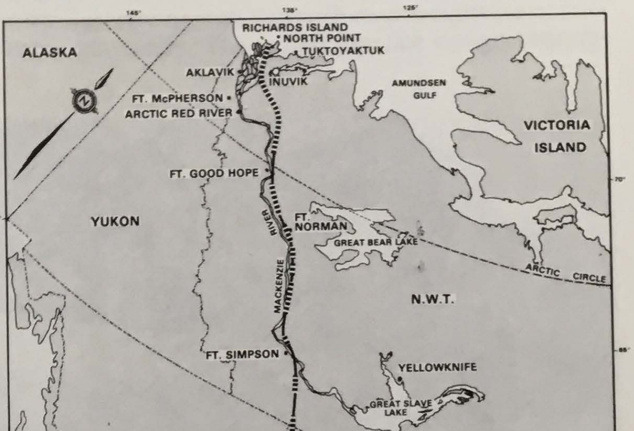


FIGURE 6.1-1 *The pipeline connecting the Beaufort Sea-Mackenzie Delta to existing systems in Alberta would be approximately 2,250 kilometres in length. The pipeline would originate on Richards Island in the Mackenzie Delta and follow the Mackenzie Valley southward to Fort Simpson and then on to Edmonton.*

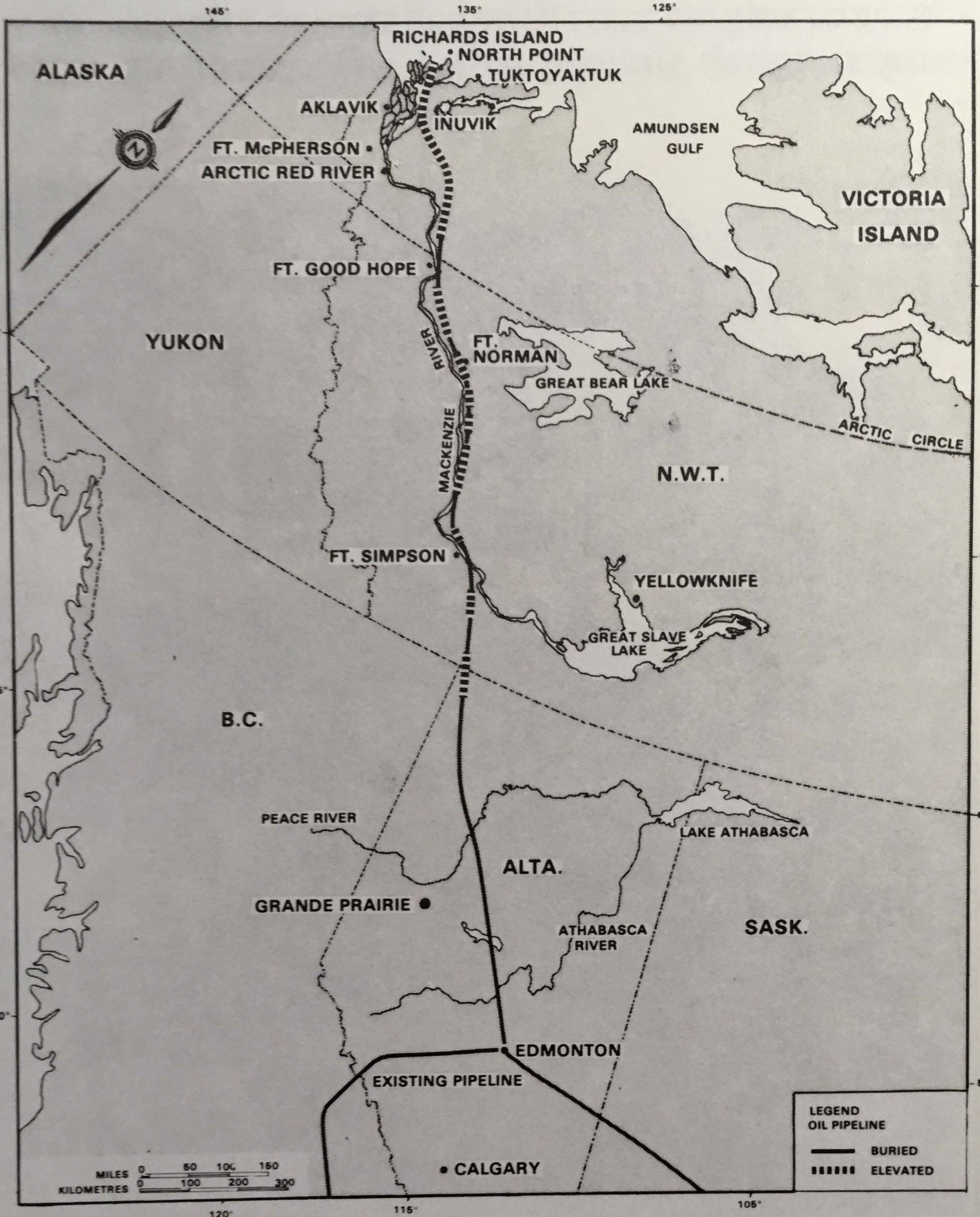


FIGURE 6.1-1 *The pipeline connecting the Beaufort Sea-Mackenzie Delta to existing systems in Alberta would be approximately 2,250 kilometres in length. The pipeline would originate on Richards Island in the Mackenzie Delta and follow the Mackenzie Valley southward to Fort Simpson and then on to Edmonton.*

Numerous route and alignment alternatives have been studied by geotechnical, environmental, socio-economic, mechanical design and construction specialists. The proposed pipeline route runs due south from the northern terminal to Parsons Lake, swings south by southeast, passing approximately 15 kilometres east of Inuvik. It parallels the Mackenzie River to a point southeast of Fort Simpson where it crosses the river. The route then proceeds to Zama and parallels the Rainbow Pipeline system until it meets and terminates at the Trans-mountain and Interprovincial pipeline terminals east of Edmonton.

The amount of land required for the pipeline, support and staging facilities, pump stations, terminal and operations and maintenance bases totals approximately 8,800 ha, of which 5,600 ha are located north of 60° North. The land requirements for the pipeline takes into account a right-of-way width of 37 m and represents about 90% of the land requirements north of 60° North. Pump stations each require an area of 182 m by 304 m, excluding the permanent airstrip if one is required.

6.1.2 PIPELINE DESIGN

The current design is based upon work carried out to define the range of technically and economically feasible flow rates and operating parameters. Prior to construction, further detailed studies will be conducted to determine the system configuration and site specific routing.

A third of the pipeline route will be constructed in permafrost terrain. A warm buried oil pipeline in this terrain could cause local thawing of the permafrost and subsequent settlement. In order to preserve the integrity of the pipeline and adjacent terrain, a maximum allowable settlement of 90 centimetres has been established. In areas where the predicted thaw settlement exceeds 90 centimetres, the pipeline may be insulated and supported above ground on vertical support members (VSM).

6.1.2.1 Elevated Mode

Approximately 720 kilometres of the pipeline will be constructed above ground (Plate 6.1-1) including the first 360 kilometres extending south from North Point. The pipe will be covered with insulation, jacketed and mounted on vertical support members (Figure 6.1-2) spaced at a nominal distance of 35 metres along the pipeline. Clearance between the pipeline and the ground surface will vary from 1.2 to 3.6 metres, depending on topography and environmental constraints for wildlife passage. The proposed spacing allows for maintaining the integrity of the pipe in the event that one vertical support member settles and fails to provide support to the pipeline.

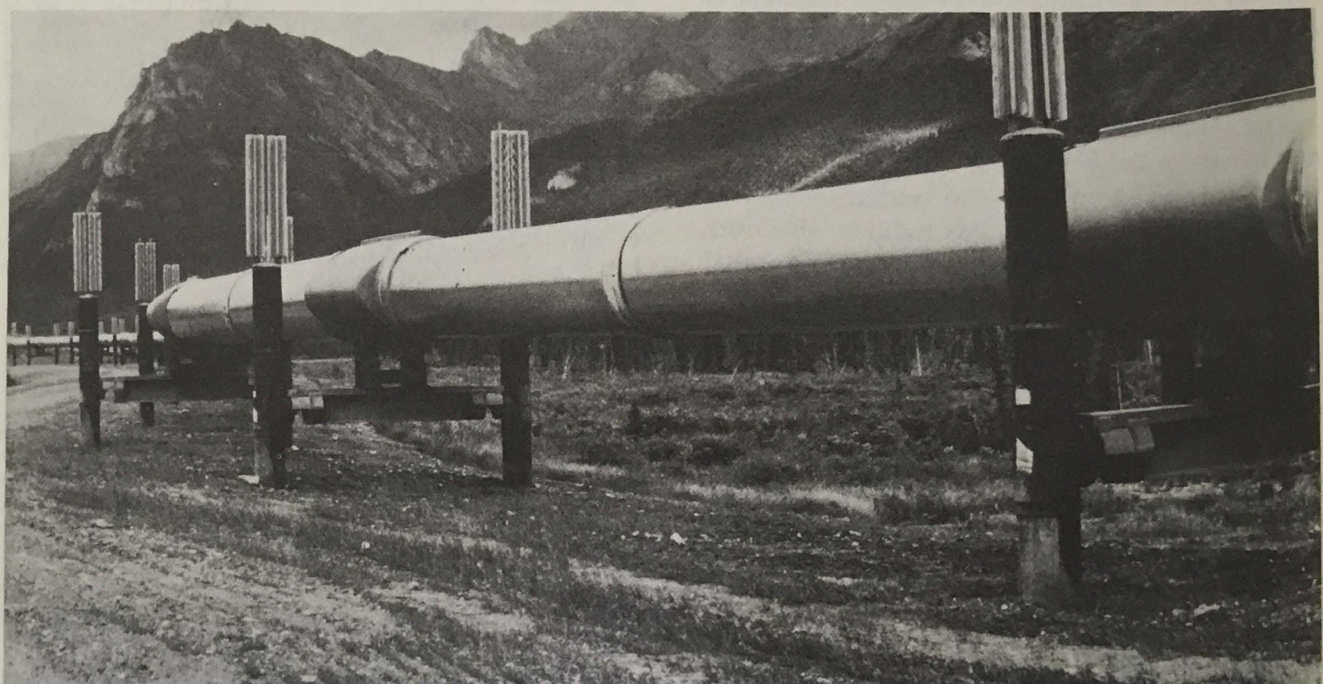


FIGURE 6.1-1 *The pipeline connecting the Beaufort Sea-Mackenzie Delta to existing systems in Alberta would be approximately 2,250 kilometres in length. The pipeline would originate on Richards Island in the Mackenzie Delta and follow the Mackenzie Valley southward to Fort Simpson and then on to Edmonton.*

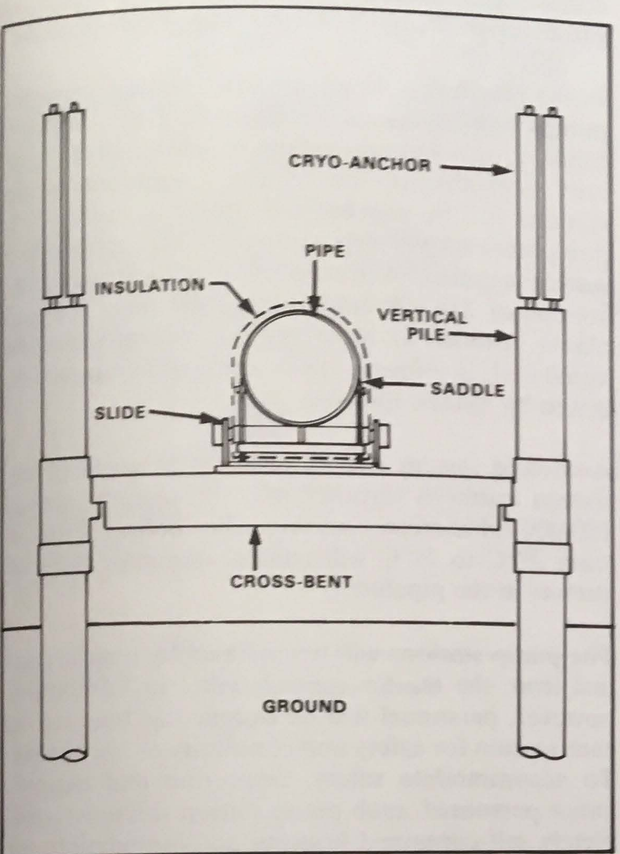


FIGURE 6.1-2 *Where elevated, the pipeline will be mounted on vertical support members incorporating a saddle and slide assembly which will permit movement as the pipeline expands or contracts. In areas where permafrost is sensitive to temperature changes the ground will be kept frozen by cryo-anchors.*

Where the permafrost is particularly sensitive to temperature changes, special thermal devices known as cryo-anchors, will be installed within each vertical support member. These devices (non-mechanical and self operating) consist of metal tubes filled with refrigerant which evaporates and condenses, thereby chilling the ground whenever the ground temperature exceeds the air temperature.

To compensate for the expansion or contraction of the aboveground pipeline caused by ambient air and flowing oil temperature fluctuations, the line will be built in a flexible trapezoidal configuration which converts changes in pipe length to a sideways movement. The pipe will be secured in a saddle and slide assembly which will permit the pipeline to move both laterally and longitudinally on the cross beam as the pipeline expands or contracts. To provide restraint of the pipeline, anchors will be positioned at a maximum spacing of 660 metres, and at all transitions from aboveground to below ground pipeline. The transition configurations will be insulated and installed with selected backfill material.

6.1.2.2 Buried Mode

Approximately 1,530 kilometres of the pipeline will be of conventional buried construction with a minimum of one metre of cover. The depth of burial will be sufficient to place the line below the normally active permafrost layer in northern areas. In high water table locations, concrete weights will be provided in order to maintain buoyancy control. In areas where differential settlement could occur, selected material will be placed in the trench bottom to prevent the localized loss of support which could result in overstressing of the pipe. The pipe will be provided with a protective coating and cathodic protection system to control corrosion. Figure 6.1-3 shows a typical cross-section of a buried pipeline.

6.1.2.3 River Crossings

Major river crossings are projected for the:

- Mackenzie River (East Channel of Delta)
- Great Bear River
- Mackenzie River (Fort Simpson)
- Peace River
- Athabasca River
- North Saskatchewan River

The pipeline will be installed below the river bed at sufficient depth to ensure safety from structural damage due to scour. The pipe will be either coated with concrete or installed with river weights to counteract buoyancy. The actual pipeline design require-

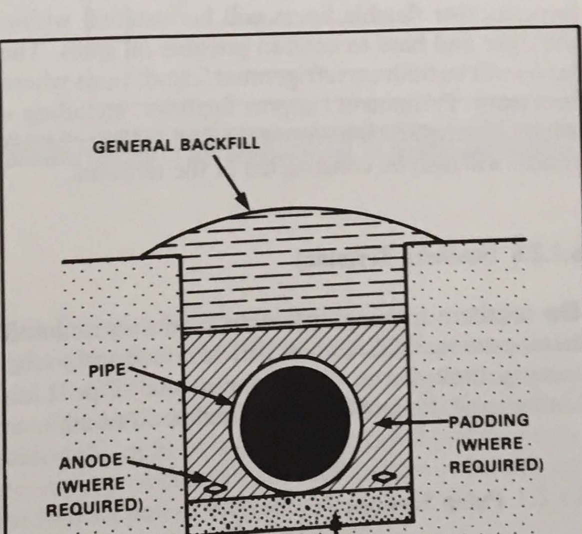


FIGURE 6.1-3 *Over a distance of about 2/3 of the route, the pipeline will be buried in a conventional manner. THis sketch illustrates the most common method of pipeline burial.*

ments at each river crossing will vary based on local conditions and will be determined during final design. The timing for installation of major river crossings will primarily be carried out during late summer when the water is at its lowest level.

6.1.2.4 Valves

Flow valves will be spaced at regular intervals along the pipeline to enable isolation of segments of the line in the unlikely event of a leak. In addition, block valves and mainline check valves will be installed at all river crossings and at other locations along the line deemed to be environmentally sensitive. The valves will be installed above ground to facilitate access and maintenance.

The valves will be operated remotely from the master control centres at Edmonton and North Point or operated locally by operators at the site.

6.1.2.5 Northern Terminal

The northern terminal will share a common site with Pump Station No. 1 and contain three covered "floating-roof" crude oil storage tanks with a total capacity to store approximately twelve hours of flow at peak average pumping rates or 99,000 cubic metres. In addition, two 2,400 cubic metres tanks will be used to store distillate fuel. The terminal will also be provided with oil metering facilities.

The crude oil storage tanks will be dyked and impermeable flexible liners will be installed within the dyke and base to contain possible oil spills. The tanks will be built on refrigerated foundations where necessary. Permanent support facilities, including a wharf, airstrip and interconnecting all-weather access roads, will also be constructed at the terminal.

6.1.2.6 Southern Terminal

The southern terminal will include oil metering and meter proving facilities and will be connected to the existing tank farms of Interprovincial Pipe Line Limited and Trans Mountain Pipeline Limited.

6.1.2.7 Pump Stations

The pump stations are designed to meet the requirements imposed by the severe northern environment. All northern stations will be constructed on gravel pads and critical areas within the station will be layered with insulation in order to keep ice-rich soils frozen and stable. All of the station equipment will be enclosed. The buildings will be insulated and interconnected by covered, heated walkways. Figure 6.1-4 shows a typical layout of a gas turbine pump station.

In the Northwest Territories, two-stage centrifugal pumps will be driven by liquid fuel gas turbines. Initially, only 4 pump stations will be required, however, as production rate increases, additional pump stations will be phased in. Ultimately twenty-four pump stations will be put into operation to provide a system capable of transporting an average daily volume of 218,000 cubic metres per day. Topping plants installed at these stations will produce the liquid fuel. In Alberta, the centrifugal pumps will be driven by electric motors.

A cooling system will be required at seven of the sixteen northern stations once throughput exceeds 150,000 cubic metres per day. The cooling of the oil from 27°C to 21°C will control thermally induced stresses in the pipeline.

The pump stations will be operated by remote control from the master control centre in Edmonton, however, personnel will be assigned as required to each station for safety and continuity of operations. To accommodate safety, inspection and maintenance personnel, each pump station will have completely self-contained housing accommodation, an electrical generating facility, a central heating plant, a water treatment plant facility and sewage and waste disposal systems. Fire detection and automatic fire extinguishing capabilities will be provided at each station.

6.1.2.8 Communications and Control

To operate and maintain the pipeline system an efficient communications and control network is essential. Communication via satellite will provide the most economical and reliable system for both construction and operating phases of the project. Private and public circuits for voice, telex and high speed data transmission between administration offices and field sites will be included.

6.1.2.9 Support Facilities

Approximately 60 kilometres of permanent all-weather access roads will be constructed to connect proposed facilities to existing public highways and temporary wharf sites. When the line is completed, these permanent access roads will be maintained for inspection and maintenance purposes. Use of these roads by the public will be controlled for safety reasons. During construction, temporary snow roads will be used to provide access along the pipeline right-of-way and to material sites north of 60° North.

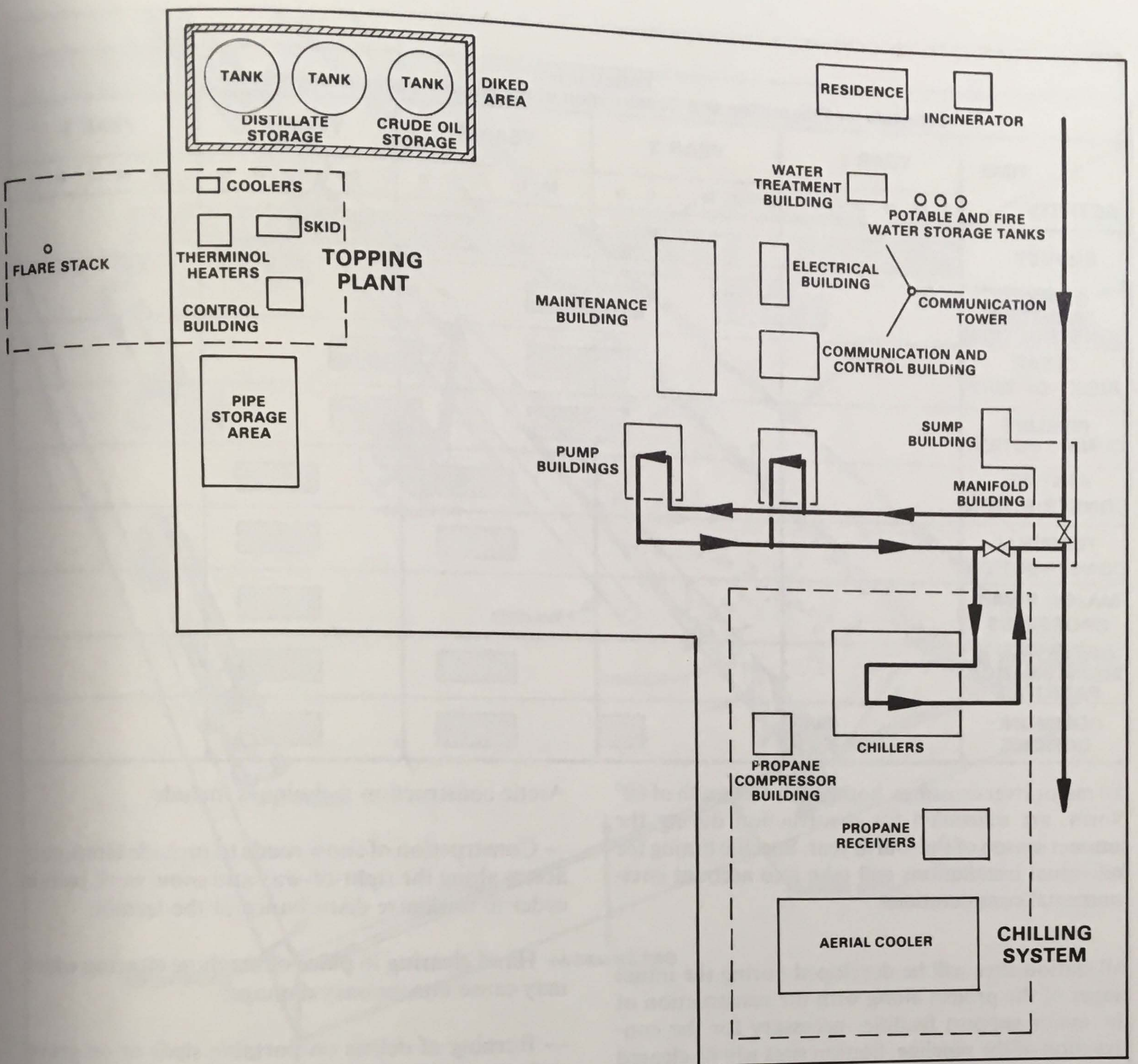


FIGURE 6.1-4 *Pump stations will be constructed along the pipeline route, some of them incorporating facilities to chill the oil in order to control thermally induced stress in the pipeline and to prevent raising of soil temperatures. A typical gas turbine pump station is shown here.*

6.1.3 CONSTRUCTION

6.1.3.1 Schedule

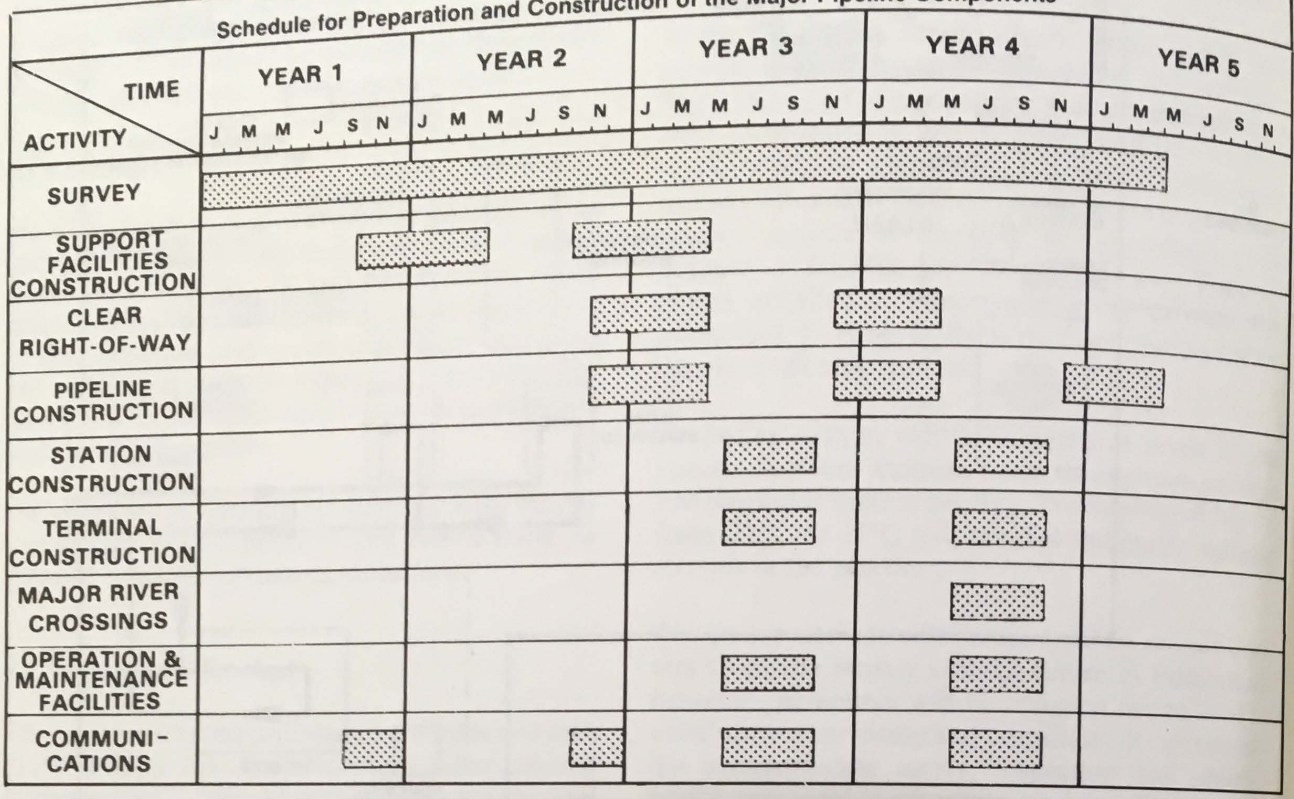
Approximately four years will be required to construct the pipeline system. Table 6.1-1 shows the schedule for preparation and construction of the major pipeline components.

The mainline will be constructed over a period of three years using eleven separate construction groups called "spreads." The length of pipeline to be constructed by each of the eleven spreads increases from north to south depending on the length of the aboveground sections.

Mainline pipeline construction within each of the eight spreads north of 60° North will be composed of two distinct operations, vertical support member installation and pipelaying. During the first winter season the right-of-way will be cleared and the vertical support members installed (where required) on the first section of each spread.

The following winter the pipelaying operations for both aboveground and belowground pipeline will be conducted on the first section of each spread, while right-of-way clearing and vertical support member installation is carried out on the second section. The pipelaying operation will be performed on the second section during the third winter season.

TABLE 6.1-1
Schedule for Preparation and Construction of the Major Pipeline Components



All major river crossings, both north and south of 60° North, are scheduled for construction during the summer season of the fourth year. Specific timing for individual installations will take into account environmental considerations.

All station sites will be developed during the initial stages of the project along with the construction of the major support facilities necessary for the construction of the pipeline. Station sites will be cleared and pads constructed to receive pipeline construction camps, materials and supplies. Actual station construction for the four pump stations required for initial operation will commence during the summer of 1985.

6.1.3.2 Construction Techniques

As a large percentage of the pipeline will be constructed in the Arctic through sensitive permafrost areas, special construction techniques are required to ensure the integrity of the line and to minimize adverse effects on the environment. The procedures required for constructing through the permafrost areas of the Arctic have evolved from winter pipelining through seasonably frozen terrain in Canada; from actual test programs such as ice and snow road construction, Arctic ditching, borrow pit development, insulated pad construction, slope stabilization, revegetation, etc; and from ongoing discussions with environmental consultants, government representatives, contractors and representatives of industry experienced in northern construction.

Arctic construction techniques include:

— Construction of snow roads to provide temporary access along the right-of-way and snow work pads in order to minimize disturbance of the terrain;

— Hand clearing in place of machine clearing which may cause unnecessary damage;

— Burning of debris on portable sleds or on gravel pads to prevent thawing;

— Use of snow fill rather than disturbing the natural terrain during grading operations;

— Locating construction camps at pump stations sites to minimize disturbance;

— Selective removal of the active layer for replacement on top of backfill mounds;

— Use of soil stabilizing methods to prevent slope instability due to thermal and alluvial erosion;

— Use of special backfill material as required for drainage, erosion and buoyancy control, grade restoration and for potentially unstable slopes;

— Extensive fertilization and revegetation following completion of construction.

Typical construction techniques for installation of buried pipeline from snow work pads are shown in Figure 6.1-5.

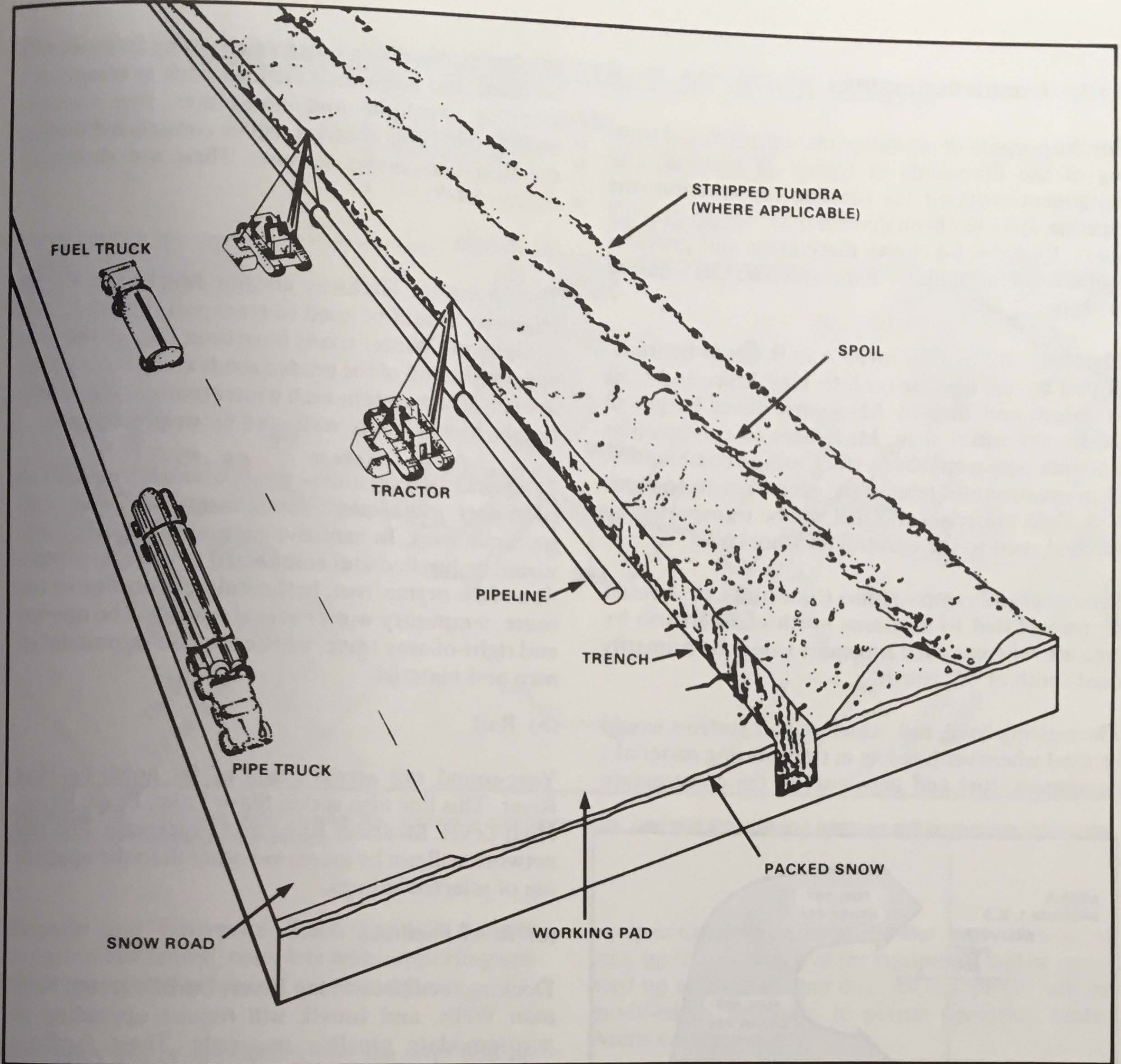


FIGURE 6.1-5 *Buried pipelines in permafrost regions will be built using snow roads for temporary access and snow work pads to minimize disturbance of the natural terrain.*

South of 65° North, the occurrence of ice rich premafrost soils begins to decrease; hence, there will be a reduced need for special Arctic construction procedures. Conventional winter construction procedures have been developed to install pipelines through areas where terrain containing muskeg could be more easily crossed when the surface was sufficiently frozen to provide adequate support for construction equipment. The pipeline right-of-way is cleared of tree cover well in advance of the main construction activities to allow for accelerated frost penetration through muskeg areas. Grading of the right-of-way follows, using cutting and filling techniques to provide a safe working surface for proper installation of the pipeline. During clearing and grading, soil is placed over the ditch line to retard frost penetration. Lengths of pipe are then strung along the right-of-way, bent to fit the contour of the ground surface, welded into a continuous string, X-rayed to prove the quality of the welds, coated with a protective coating, weighted as required with concrete to control buoyancy. The mound of soil placed over the ditch line during clearing and grading is removed and the ditch excavated just prior to lowering the pipeline into the ditch to ensure that the excavated material used for backfill contains as little frozen material as possible. Following backfill, the pipeline is pressure tested with warm water or a water methanol mix to prove its integrity. The natural contours of the right-of-way are then restored and revegetation commenced.

6.1.3.3 Construction Logistics

For the purpose of providing management and routing of the thousands of tonnes of material and equipment required for pipeline construction, the pipeline route has been divided into four geographic areas. Figure 6.1-6 shows these areas and provides estimates of the quantity of material and fuel required in each.

Materials and fuel for areas A & B would be transported by rail and/or road to Hay River and Fort Simpson, and then by Mackenzie River barges to temporary wharf sites. Movement to construction stockpile sites would be by truck using a combination of permanent and temporary winter roads. In areas C & D all materials and fuel will be transported by rail and road to the construction stockpiles.

Personnel and camp supplies (foodstuffs, etc.) would be transported to locations north of 60° North by aircraft, whereas road transport would be primarily used south of 60° North.

The existing road, rail, water and air systems would be used whenever possible in transporting materials, equipment, fuel and personnel to the construction stockpiles. Modifications to the existing facilities will be made and additional facilities such as temporary wharves, stockpile and camp sites, fuel storage, access roads and airstrips will be constructed during the first two winter seasons. These are shown in Figure 6.1-7.

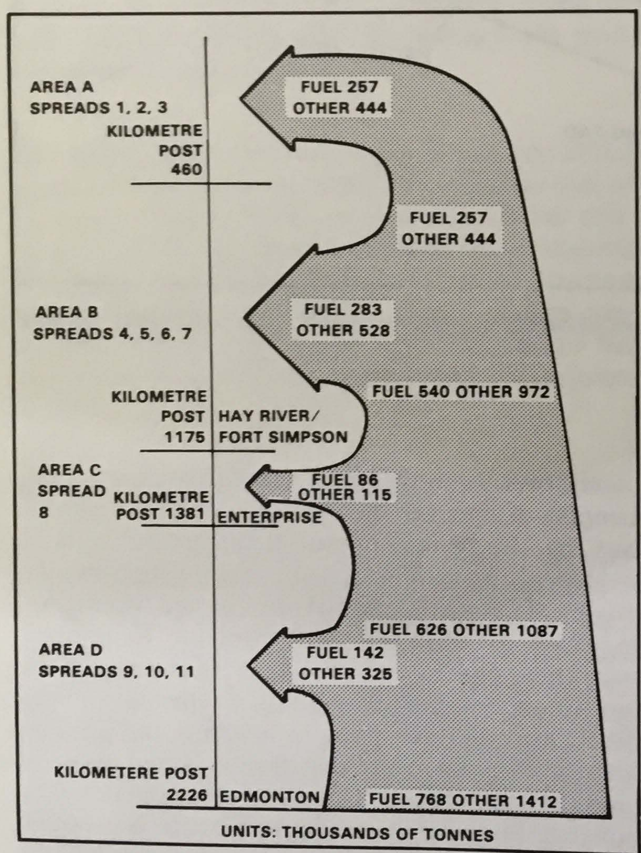


FIGURE 6.1-6 *For management and routing of material and equipment required for pipeline construction, the route has been divided into four areas. Volumes of materials and fuel have been estimated for each segment as shown (thousands of tonnes).*

(a) Roads

The Dempster Highway and the Mackenzie Valley Highway would be used to transport materials and equipment. Winter roads have been used in the past beyond the end of the graded roads and it is proposed to open and maintain such winter roads as necessary. Loads, however, are restricted by weight and size.

Temporary winter access roads would be required to transport materials from existing facilities and stockpile sites. In sensitive permafrost areas, snow would be levelled and compacted to provide protection of the permafrost. In the southern portion of the route, temporary winter access roads will be opened and right-of-way travel will be used for movement of men and material.

(b) Rail

Year-round rail access exists as far north as Hay River. This line also serves Slave Lake, Peace River, High Level, Meander River and Enterprise. The rail network will not be increased other than the upgrading of selected sidings.

(c) River Facilities

Docking facilities at Hay River, Fort Simpson, Norman Wells, and Inuvik will require upgrading to accommodate pipeline materials. These facilities would be supplemented by the construction of temporary wharves at strategic points along the river. A permanent wharf at Hansen Harbour would be constructed to service the North Point Terminal. Temporary wharves would be removed at the end of each barging season. Procedures will be established so that no disruption of resupply to existing communities will occur during the pipeline construction period.

(d) Air Facilities

Existing airstrips at Inuvik, Norman Wells, Fort Simpson and Hay River, together with up to five 1,830 m and twelve 732 m airstrips are proposed along the route to serve construction, operation, and maintenance functions. Temporary runways, on ice or snow, may also be utilized during construction.

(e) Staging Sites and Stockpiles

Facilities for receiving and storing materials and equipment would be established at Hay River, Fort

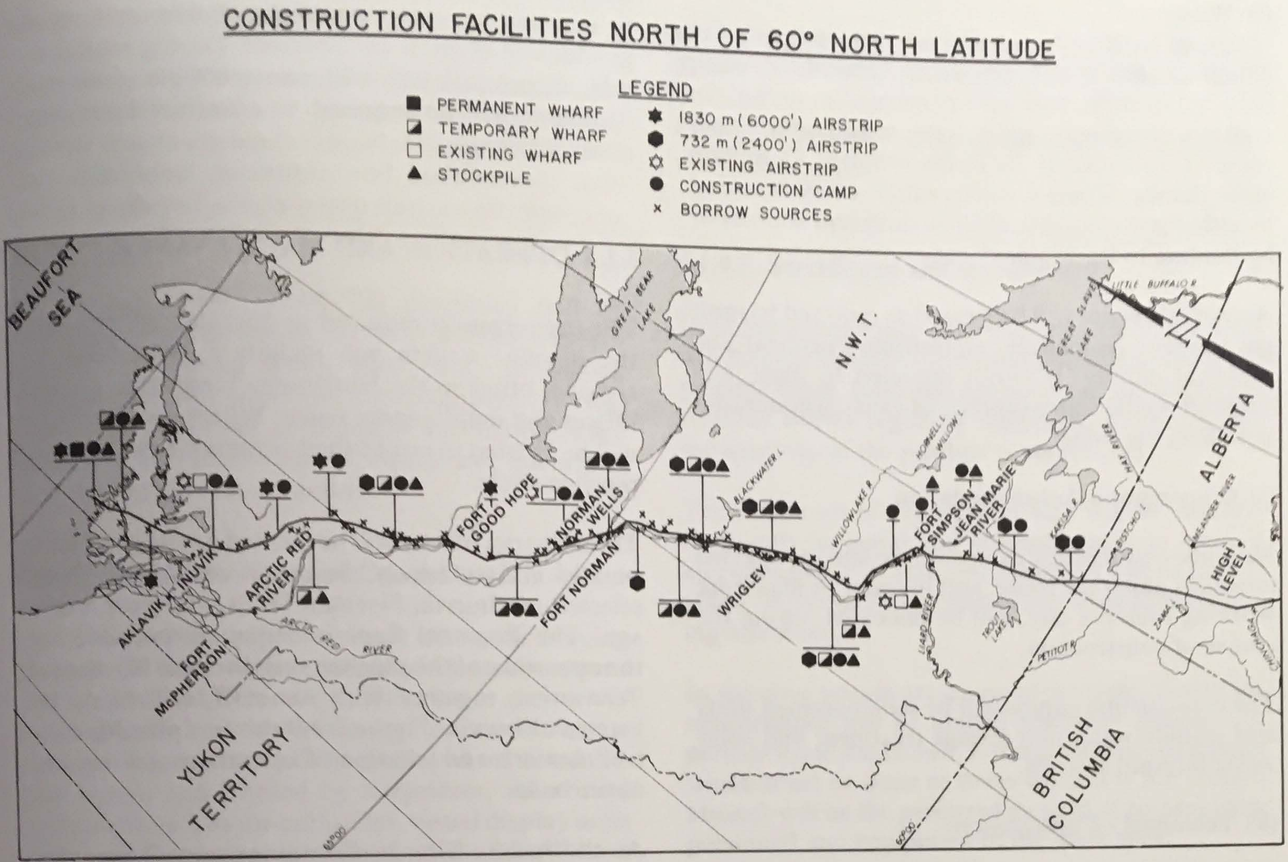


FIGURE 6.1-7 *Facilities such as wharves, stockpile and camp sites, fuel and storage and airstrips will be required along the pipeline route to support construction.*

Simpson and Enterprise. Each site will be self-contained and fenced, complete with supporting utilities, services and personnel accommodation.

Stockpiles will be provided along the river and the route of the pipeline. Where these sites are serviced by road or rail, they will be situated close to the right-of-way. Where serviced by temporary wharves, they would be generally located in the immediate vicinity of the off-loading area. To minimize terrain disturbance, stockpiles would be located, where possible, on pump station pads.

Fuel required north of Fort Simpson would be transported by rail or road tankers to Hay River or Fort Simpson and transferred to barges for delivery to stockpile locations.

South of Fort Simpson fuel would be transported directly to the construction sites by truck.

(f) Equipment

Estimated equipment requirements for the construction of the mainline pipeline north of 60° north latitude exceeds 6,000 pieces of pipeline construction equipment, ranging from crawler type tractors to pick-up trucks. Much of the equipment will be operated up to 24 hours per day. All equipment will be modified as necessary to permit operation under Arctic conditions.

(g) Materials and Supplies

It is expected that Canadian companies can supply the mainline pipe and a large percentage of the components required for the construction and operation of the pipeline system.

(h) Borrow

Approximately 8 million cubic metres of borrow material is estimated to be required north of 60° N to construct airstrips, access roads, stockpile sites, station pads, camp sites, staging sites and wharves. Borrow sources, as identified for Beaufort Delta Oil Project Limited by Techman Limited (1976), were reviewed and those most suitable to this project are shown in Figure 6.1-7. In addition, it is also likely future surveys along the right-of-way will identify other borrow sources which may be better suited to the construction project.

(i) Water

North of 60° North the total volume of water required over the four-year construction period for construction camps, hydrostatic testing and winter roads is estimated to be in the order of 43 million cubic metres. Where possible, water will be obtained by either pumping directly from adjacent sources or by hauling to the required site.

All potable water will be treated as required to meet government regulations concerning chemical and bacterial quality. It is not intended to place any demand on the water supplies of existing communities along the route.

(j) Construction Accommodation

Mainline construction camps will be sited at selected locations along the route, and in order to maximize working time per day, will be relocated during the course of construction.

The construction camps will be self-contained units and include water and sewage treatment and solid waste disposal systems.

(k) Personnel - Construction

Figure 6.1-8 shows an estimate of peak manpower required by construction season, north of 60° North. During the peak construction period approximately 13,500 people will be required. After completion of the pipeline, construction personnel will continue to be required to construct additional pump stations as production of crude oil increases. During peak periods, approximately 600 construction personnel (summer) will be required to construct these new pump stations.

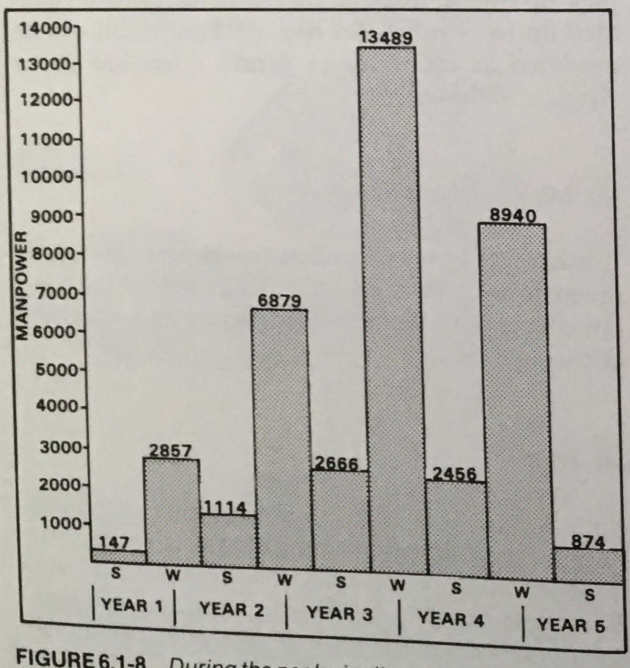


FIGURE 6.1-8 *During the peak pipeline construction period, about 13,500 people will be required. This graph shows the peak manpower requirement by construction season.*

6.1.4 OPERATION AND MAINTENANCE

The organization required to operate and maintain the pipeline system will include a head office, a regional office in the Northwest Territories, district offices and maintenance bases. Where possible these will be located in established communities along the pipeline route.

Three district offices will be located north of the 60th parallel, and tentatively, the locations which have been selected are Inuvik, Norman Wells, and Fort Simpson. The Regional Superintendent responsible for the operation of the pipeline system in the Northwest Territories, together with his staff, will likely be located at Inuvik. Figure 6.1-9 shows a possible control network and location of operation and maintenance bases.

At the head office in Edmonton, an Operations Manager will be responsible for operating and maintaining the complete pipeline system. His staff will include personnel involved with technical services, oil shipments, operations, administration and accounting and clerical functions. The Operations Manager's staff will also include trained operators and technicians located at the North Point back-up control centre.

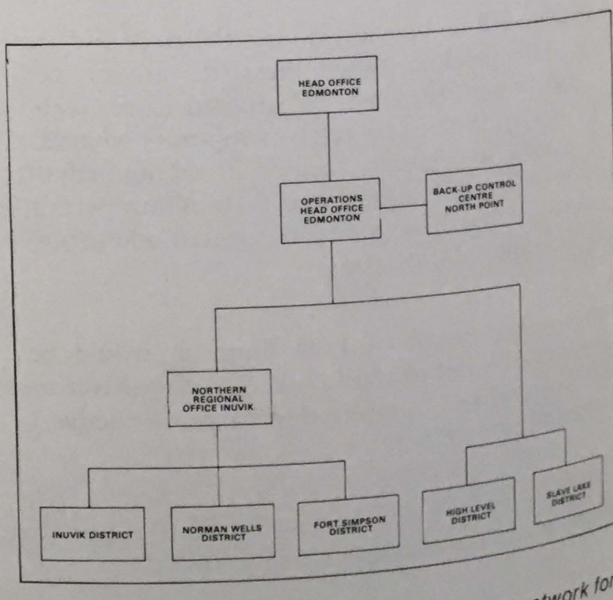


FIGURE 6.1-9 *Possible structure of a control network for an overland pipeline system.*

6.1.4.1 Personnel Requirements

Approximately 200 personnel will be required in the Northwest Territories to operate and maintain the pipeline system during the initial five years of operation. Additional operations and maintenance staff will be employed as new pump stations are added to the system.

By the year 2000, about 300 personnel will be required in the Northwest Territories. Positions will include experienced senior supervisory personnel, engineers, aircraft pilots and flight engineers, clerical and stores personnel, technicians and maintenance personnel such as mechanics, equipment operators, welders and general labourers.

6.1.4.2 Communications and Control

Operation of the pipeline, once oil starts moving through the line, will be controlled by an operations control centre at Edmonton. This master station will automatically and continuously monitor all remote stations. Information will be displayed on visual display panels and printed by teleprinter. All critical equipment such as the computer, visual display units and control panels will be duplicated and will have automatic changeover capabilities.

Pipeline dispatchers will be responsible for monitoring and controlling the flow of crude oil from North Point to Edmonton twenty-four hours a day. Using the control centre data, pipeline dispatchers will be able to control pipeline flow rates, system startup and shutdown, starting and stopping of individual pumps at all pump stations, pump station pressures and pipeline and pump station block valves. Station data displays will also show the status of valves and pumps at each station plus information on the operating suction pressure, flow and temperature. Constant surveillance of the pipeline operation from North Point will also be available.

Leak detection systems will be included as part of the overall control system. These systems will have the ability to detect and identify the location of a leak down to 0.25 to 0.5 percent of pipeline flow. A computer will monitor the pipeline for leaks and upon detection of a leak or a suspected leak, will sound an alarm and indicate the section of the line with the problem. The dispatcher, subject to the operational procedures established with regard to leaks and suspected leaks, will if necessary then be able to shut down the pipeline, isolating the section in question by closing the appropriate pipeline valves.

Recent advances in the design of leak detection systems would indicate that the leak detection system proposed for this overland pipeline system would allow the pipeline to be shut-in before 20 to 40 cubic metres of oil would have escaped from a minor leak.

Communications for the system will be via microwave and satellite.

6.1.4.3 Surveillance and Maintenance

Detailed surveillance and maintenance procedures will be developed to meet local conditions along the pipeline route. Both aboveground and belowground sections will be regularly monitored to ensure that the integrity of the pipeline is maintained.

The condition of the right-of-way will be checked frequently by aerial and ground patrols to identify any subsidence or erosion. Measures will be undertaken immediately to remedy any situations requiring attention.

In sensitive terrain areas, use of the right-of-way for maintenance will be limited whenever possible, to periods when it is frozen. For maintenance or repairs which must be done at times when it is not frozen, aircraft will be the preferred method of transporting personnel and equipment to the work sites.

At all times, personnel will ensure that the use of the right-of-way is kept to a minimum and that consideration be given to all environmental factors which exist in the area.

Low ground pressure vehicles containing specialized equipment will be maintained at all remote pump stations for use in the event of any emergency.

6.1.4.4 Waste Disposal

Incorporated into the pump station design will be a vacuum sewage system to collect the black water (toilets and urinals) and grey water (showers, hand basins, etc.). The black water and combustible solid waste will be incinerated. Incineration eliminates hauling to off-site locations and the need for sewage lagoons. Large pieces of scrap metal will be compacted and stockpiled in suitable areas for recycling as scrap.

6.1.5 POTENTIAL ENVIRONMENTAL DISTURBANCES

The pipeline would be constructed over a period of about four years. The majority of construction activity will take place during winter when terrain is frozen. Summer construction activities include the construction of pump stations, the northern terminal

and the major river crossings. The environmental implications posed by these and other activities related to a major pipeline down the Mackenzie Valley corridor are examined in Volume 4.

6.1.5.1 Preconstruction and Construction Activities

Preconstruction and construction activities related to the pipeline which may create environmental disturbances include: surveying, site clearing, ditching, blasting, hauling and stringing pipe, ditch backfill and borrow excavation. Indirect activities which may impact upon the environment include those related to construction camps, the transport of supplies and equipment, building of access roads, wharfing facilities, and pumping stations.

(a) Right-of-Way

A corridor approximately 37 metres wide will be required for the pipeline.

(b) River and Stream Crossings

Water crossings will involve the movement of equipment across streams during trenching and backfilling, cutting of banks and underwater blasting in areas underlain by rock or impervious sediments.

(c) Borrow Pits

Gravel will be required for pump station foundations, access roads, pipeline ditch bedding and select backfill material. Borrow pits will be excavated to supply material for these requirements.

(d) Construction Camps

The impact associated with construction camps in the Arctic is described in Section 5.3.

(e) Other

Impacts associated with pipeline construction also include noise and atmospheric emissions due to the movement of people, machinery and aircraft.

6.1.5.2 Operations and Maintenance

Disturbances associated with pipeline operation and maintenance are summarized as follows:

(a) Surveillance

Pipeline surveillance overflights will be of a temporary and intermittent nature. Altitude restrictions will ensure that only minimal noise disturbance is caused at ground level.

(b) Roads and Wharves

Permanent roads and wharves will be used for resupply and maintenance traffic.

(c) Pump Stations

Pump stations will each require about 5.5 ha of land. Each pumping station will be fully automated and remotely controlled when operational, so impacts will be from the mechanical elements with potential human disturbance only in the event of emergency maintenance.

Combustion of fuel in the turbines at the pump station will result in gaseous emissions. Noise will be controlled to prescribed levels at the plant fence.

6.2 OVERLAND GAS PIPELINE SYSTEMS

In the last 10 years considerable research, design engineering, environmental and socio-economic studies have been completed by various project groups to assess the feasibility of transporting natural gas from the Beaufort Sea and Arctic Islands to southern Canadian and United States markets. In 1974, Canadian Arctic Gas Pipeline Ltd. filed an application to the NEB requesting authorization to construct and operate a pipeline system capable of transmitting gas produced in northern Alaska and the Mackenzie Delta to southern markets. A year later, Foothills Pipeline Limited submitted an application to construct and operate a smaller diameter pipeline (the Maple Leaf project) that would carry only Mackenzie Delta gas south to Canadian markets.

In 1976, Foothills Pipeline (Yukon) Limited, filed an application with the National Energy Board for a certificate of public convenience and necessity to construct an alternate pipeline to that proposed by Canadian Arctic Gas Limited, routed through Alaska and the Yukon Territories via the Alaska Highway. This pipeline would transport Prudhoe Bay gas to the United States markets and is referred

to as the Alaska Highway Gas Pipeline Project. As a condition of approval, Foothills agreed to make a further application to the NEB which would consider the Dempster Link covering construction and operation of a pipeline lateral from the Mackenzie Delta to connect with the Alaska Highway Gas Pipeline near Whitehorse (shown in Figure 6.2-1).

In 1977, Polar Gas submitted applications to the Department of Indian Affairs and Northern Development and the NEB, to construct a gas pipeline originating on Melville Island and whose route crosses Somerset Island and parallels the west side of Hudson Bay, terminating at Longlac, Ontario. Polar Gas subsequently withdrew this application in 1977 in favour of a new application for a combined "Y" pipeline system (Figure 6.2-2). This route configuration is intended to connect gas discoveries both in the Arctic Islands and the Mackenzie Delta-Beaufort Sea areas to central Canadian markets.

As outlined above, both the Dempster Lateral Pipeline Project and the Polar Gas Project ("Y" line) proposed that transmission lines would be constructed to carry natural gas from three major fields (Niglintgak, Parsons Lake and Taglu) to main trunkline systems. These laterals were sized to accommodate the production from these reservoirs. With the discovery of oil in the Beaufort Sea, gas associated with the oil could add considerable volumes to the existing reserves. As additional oil and gas discoveries are made, the construction of a dedicated gas pipeline system from the Beaufort Sea-Mackenzie Delta region down the Mackenzie Valley to connect with existing gas transmission systems in Alberta (similar to the Foothills Maple Leaf application) could become an attractive alternative. This would then establish a single energy corridor for hydrocarbon transportation and could also be a potential source of fuel for communities located along the Mackenzie River. The pipeline size would depend on the existing and potential reserves in the area at the time design studies commence.

Brief project descriptions are presented here and are extracted from the various company submissions. The proponents do not intend to submit supporting documentation covering the gas transmission systems mentioned since these applications have been filed with Federal regulatory agencies and as such are available for public review.

6.2.1 DEMPSTER LATERAL PIPELINE PROJECT

The Dempster Lateral Gas Pipeline is designed to carry an average volume of 34 million cubic metres of natural gas per day from the Mackenzie Delta to the Alaska Highway Gas Pipeline and thus to southern markets.

The proposed gas transportation system will connect the Taglu, Parsons Lake and Niglintgak gas fields in the Mackenzie Delta, and possibly other reserves, to a trunkline system. An 18 kilometre lateral will link the Niglintgak gas field to the mainline at its northern point of origin (kilometre post O at the Taglu plant site) on Richards Island in the Mackenzie Delta. A 20 kilometre lateral will connect the Parsons Lake gas field to the main line at kilometre post 82. The mainline will extend 1,200 kilometres from the Mackenzie Delta, generally following the Dempster and Klondike highways to Whitehorse (Figure 6.2-1).

The pipeline will be designed and constructed in the buried mode. A total of eight automated compressor stations would be constructed to ultimately transport 34 million cubic metres of natural gas. Gas chillers will be installed at the first four compressor stations to maintain gas temperatures below 0°C to maintain permafrost integrity. South of kilometre post 700 the gas will be maintained at temperatures above 0°C. Each compressor station site will consist of a fenced pad of approximately 4 hectares which will include the compressor building, scrubber, utility gas metering and control compound, gas chilling or heating equipment, work shop and office complex and, where required, a separate area for living quarters.

Gas metering facilities will be provided to measure flow into the pipeline at the Niglintgak, Taglu and Parsons Lake gas plants. In addition, a meter station will be installed at the junction with the Alaska Highway Gas Pipeline to monitor flow out of the Dempster Lateral.

The Foothills Pipe Lines (South Yukon) Ltd. operation and maintenance organization, established for the Alaska Highway Gas Pipeline, will be responsible for the operation of the Dempster Lateral. The head office, warehouse, technical maintenance, and operations centre for this organization will be located at Whitehorse. Area offices would be established at Inuvik, Eagle River, Dawson City and Carmacks, with a materials supply depot included at Inuvik.

The Dempster Lateral is sized based on natural gas production from three major gas plants in the Mackenzie Delta region and does not have capacity for the additional gas reserves which may be associated with future oil and gas discoveries. A re-evaluation of gas reserves will be conducted at a later date, at which time the optimum pipeline size will be selected.

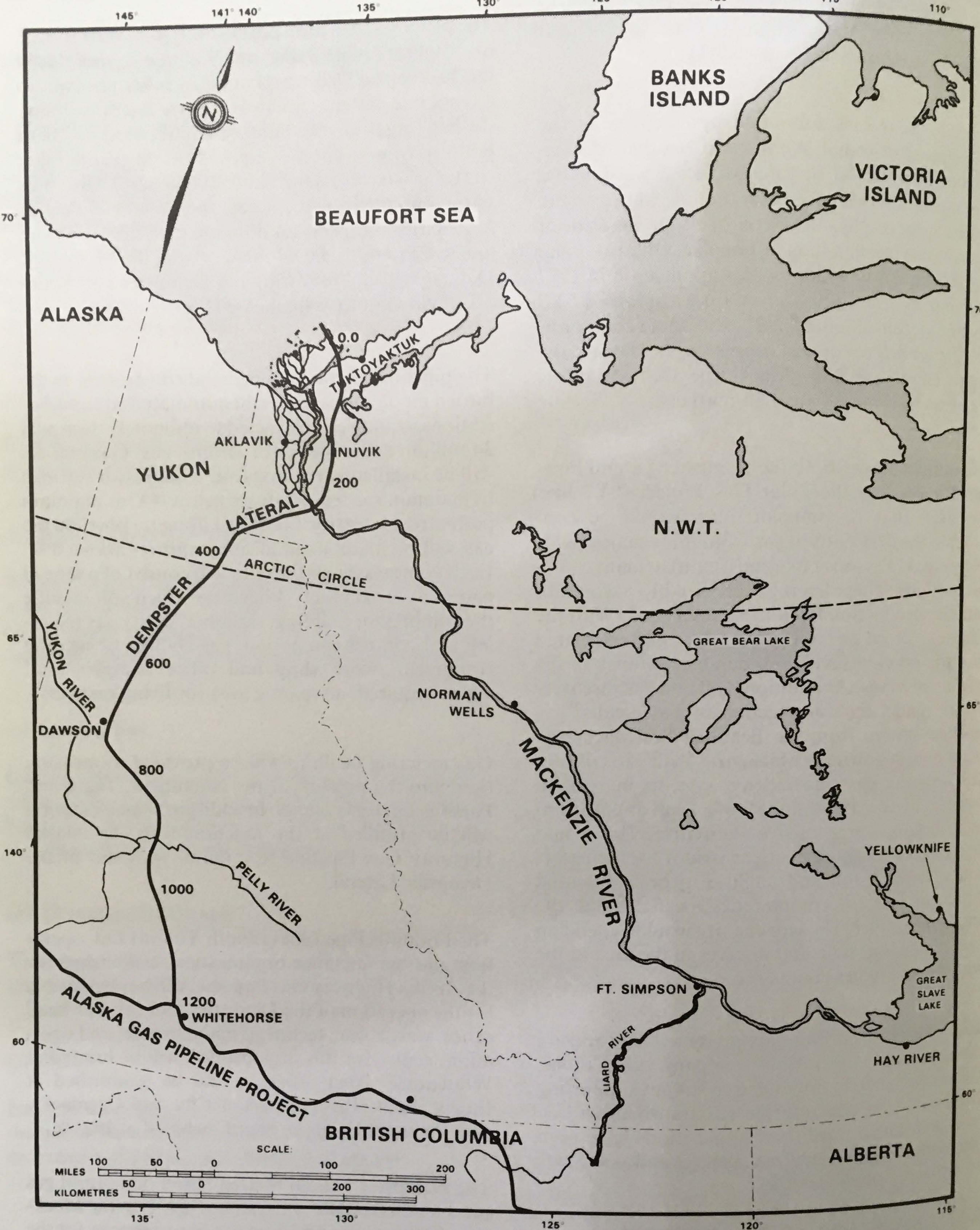


FIGURE 6.2-1 *The proposed Dempster Lateral Gas Pipeline would carry gas from the Mackenzie Delta to join the proposed Alaska Highway Gas Pipeline near Whitehorse in the Yukon.*

6.2.2 POLAR GAS PIPELINE PROJECT

The Polar Gas Project was formed in 1972 to study and develop the best way of transporting natural gas from discoveries made in the Arctic Islands by Panarctic Oils in the early 1970's. The project participants are Trans Canada Pipelines (project manager), Panarctic Oils Ltd, Tenneco Oil of Canada, Ltd., Ontario Energy Corporation and Petro-Canada. By 1973, it was determined that a large diameter pipeline was the most economical and efficient means of moving large quantities of gas to southern Canadian markets. As a result, studies have been directed at determining the optimum route for the pipeline system. By 1974, project research was focussing on a route which crossed Barrow Strait, Somerset Island and travelled down the west side of Hudson bay to terminate at Longlac, Ontario (Figure 6.2-2). Between 1973 and 1977 some 10 million dollars were spent on the environmental and socio-economic studies required to prepare a thorough environmental impact statement. In late 1977 Polar Gas submitted applications and accompanying documentation to the Department of Indian Affairs and Northern Development and the National Energy Board, including engineering, environmental, socio-economic and cost criteria for this route. This application was referred by DIAND to the Federal Environmental Assessment and Review Office which in turn established an environmental assessment panel to review the project. At the request of Polar Gas, this application was subsequently withdrawn in May 1980 after further studies established the feasibility of a combined "Y" pipeline system. This route configuration would connect gas discoveries in both the Arctic Islands and the Beaufort Sea - Mackenzie Delta to central Canada through one common system.

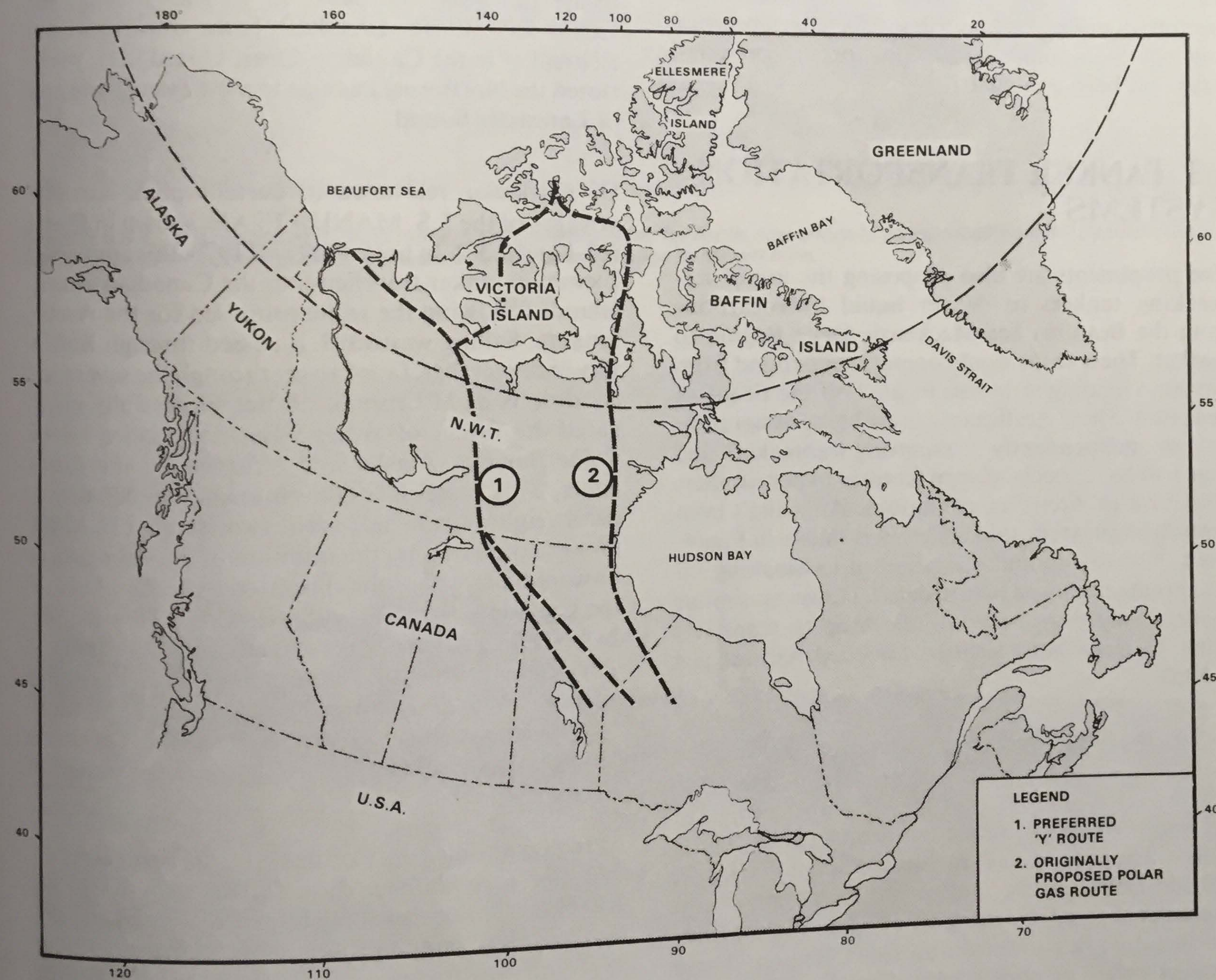


FIGURE 6.2-2 *A pipeline is proposed by the Polar Gas Project to transport gas from the Arctic Islands to Ontario. An alternative for transporting Mackenzie Delta-Beaufort Sea gas would be to tie into this line.*

The "Y" alternatives all incorporate a lateral from Melville Island, across M'Clure Strait to Victoria Island and then across Dolphin and Union Strait to the mainland Northwest Territories west of Coppermine. This lateral would then join another lateral from the Mackenzie Delta, and proceed to southern Canada by one of the three routes: the eastern "Longlac" route, passing to the east of Great Bear Lake and roughly following the tree line through Northern Manitoba to the Trans Canada Pipeline system in Northern Ontario; the "Mackenzie Valley" route, generally following the east side of the Mackenzie River; and the "East Franklin" route, which would cross the uplands to the east of the Franklin Mountains. The "Y" line to Longlac is currently the project's preferred route, but the Mackenzie Valley and East Franklin routings remain viable alternatives.

Although the exact timing of the Polar Gas application for the "Y" line to Longlac is still under consideration, documentation covering the environmental and socio-economic statements for the preferred route has been completed.

6.3 TANKER TRANSPORTATION SYSTEMS

The proponents are also proposing the use of icebreaking tankers to deliver liquid hydrocarbons from the Beaufort Sea-Mackenzie Delta Region to market. These ships would operate year-round from northern loading terminals located off the Beaufort Sea coast. These Arctic tankers are being designed to operate independently of escorting icebreakers and thus will have special design features to permit their operation in Arctic ice conditions. An artist's conception of an Arctic tanker design is shown in Figure 6.3-1. The design and operation of icebreaking oil tankers are discussed here in detail. However, similar tankers may also eventually be used to transport other hydrocarbons such as liquefied natural gas (LNG).

Experience gained with the operation of icebreakers in the Arctic and data collected from operation of the CANMAR KIGORIAK in the Beaufort Sea have allowed designers to refine the details of the Arctic tanker. The proponents are thus confident that large, 200,000 DWT, Arctic tankers can be designed and constructed to safely transport oil, year-round, from the Beaufort Sea - Mackenzie Delta Region. These tankers would be registered in Canada and be governed by all existing applicable Canadian and international regulations.

The use of icebreaking tankers for year-round transportation in Arctic waters presents physical, technical and human challenges, but these are being met. There has been some experience of marine operations through the Northwest Passage in winter and a considerable body of knowledge and experience has been gathered through the operation of ships in ice-covered waters in other parts of the world.

Canadian Coast Guard icebreaker operations in the Arctic usually last from late July to early October. However, there have been some significant extensions to this season. In mid December 1966, the CCGS JOHN A. MACDONALD and CCGS N.B. MCLEAN escorted the icebreaking cable repair ship CCGS JOHN CABOT to Thule, Greenland, at the northernmost extremity of Baffin Bay. In September 1967, the CCGS JOHN A. MACDONALD and the USCG STATEN ISLAND travelled from the eastern Arctic to the Beaufort Sea in order to escort to safety the icebreaker USCG NORTHWIND which had been disabled at 79°N 169°W, that is 700 kilometres inside the polar ice pack. In February 1972, the CCGS LOUIS ST. LAURENT, the most powerful icebreaker in the Canadian Coast Guard fleet, penetrated the Northwest Passage to the westernmost end of Lancaster Sound.

Of particular relevance to current plans are the voyages of the S.S. MANHATTAN, shown in Plates 6.3-1 and 6.3-2. In both 1969 and 1970, this converted Exxon oil tanker travelled into the Canadian Arctic Islands following the route proposed for the Arctic tankers. Sailing westward, it passed through Baffin Bay in September, failed to get through the severe ice conditions of M'Clure Strait but successfully navigated the Prince of Wales Strait, then sailed on to Point Barrow, Alaska and returned by the same route. This vessel is a conventional, 106,000 tonne deadweight, steam powered, twin screw (32 MW) tanker converted by the addition of an icebreaking bow and side sponsons. Escorted by icebreakers of the Canadian and United States Coast Guards, the MANHATTAN was very successful operating in Arctic conditions, often using her higher mass and shallow angle bow to break ridges beyond the capability of the Coast Guard icebreakers. On these voyages, data were collected for use in the design of future icebreakers.

As for operating cargo icebreakers, the first vessel of this type to be launched in Canada was the M.V. ARCTIC. This icebreaking bulk cargo vessel, owned by Canarctic Shipping Ltd., made its first voyage in 1978 and now trades regularly to the Nanisivik mine on Northern Baffin Island (June to November) and to the Polaris Mine on little Cornwallis Island (August to November).

The U.S.S.R. has also made significant advances in the design and operation of icebreakers. In 1977, the

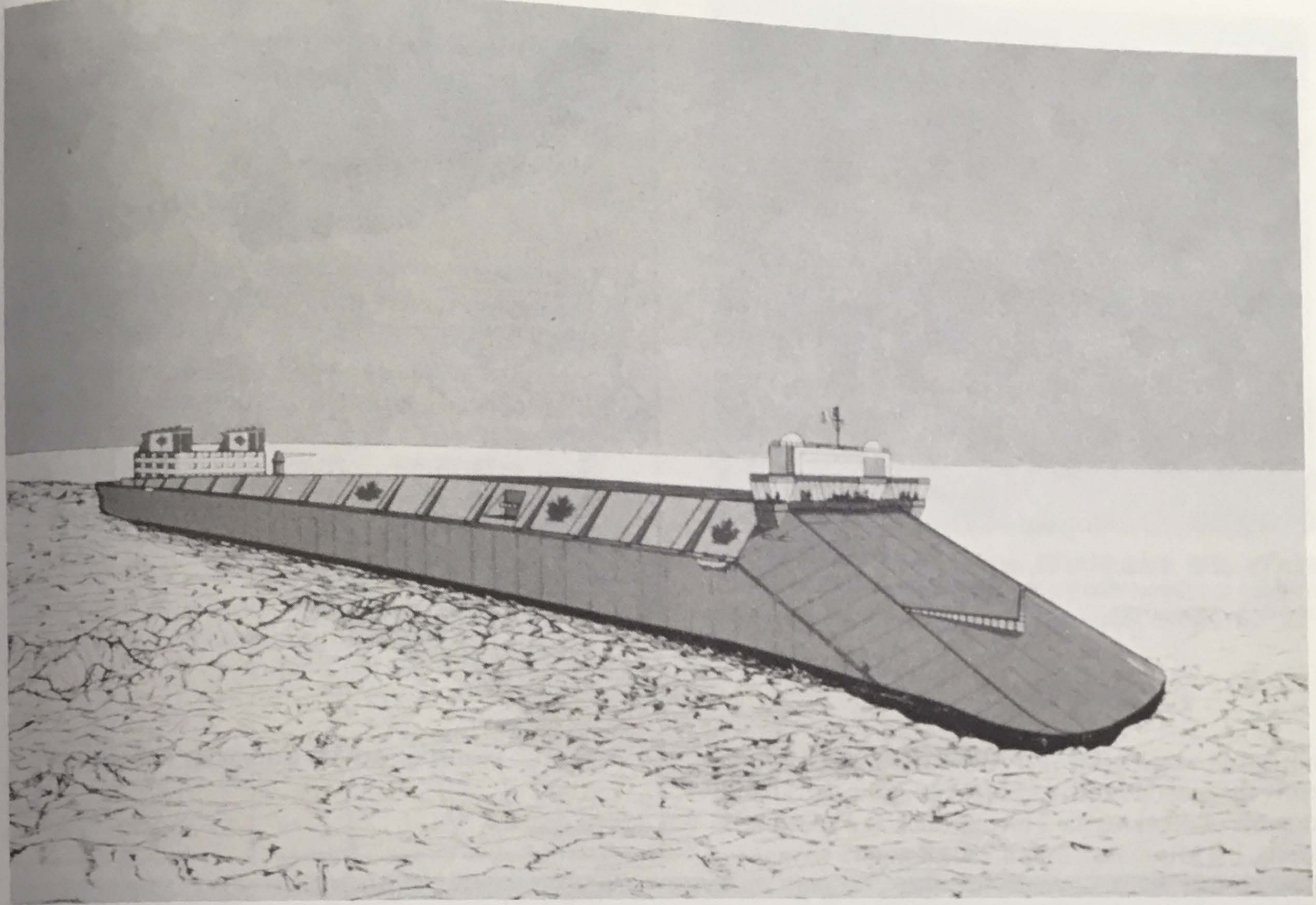


FIGURE 6.3-1 *It is proposed to build tankers specially designed for Arctic operations to transport oil from the Beaufort Sea to markets. An artist's conception of a possible Arctic tanker design is shown here.*

PLATE 6.3-1 *In 1969 and 1970, the S.S. MANHATTAN, a converted oil tanker, travelled through the Canadian Arctic along the route proposed for tankers operating to the Beaufort Sea. This voyage demonstrated the feasibility of icebreaking tanker transport.*

PLATE 6.3-2 *During the voyages of the S.S. MANHATTAN through the Arctic, data were collected for use in the design of future icebreakers.*

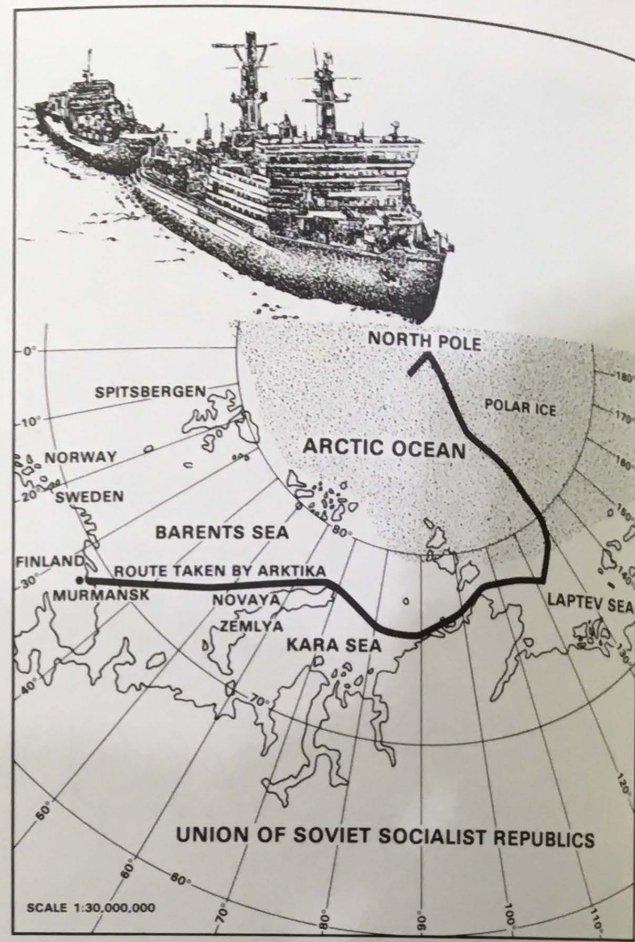


PLATE 6.3-3 *In 1977, the Soviet icebreaker ARKTIKA became the first surface ship to reach 90° latitude, after travelling 2,500 kilometres through the Polar pack ice. The Soviet icebreaker is a 55.2 Megawatt nuclear powered vessel. (Courtesy Novosti Press Agency)*

nuclear-powered icebreaker ARKTIKA, which is presently the most powerful icebreaker in the world and capable of breaking ice 2 metres thick at a speed of 3 knots, left Murmansk for a 4,230 kilometre voyage to the geographic North Pole. On August 17, after an 8 day voyage including 2,500 kilometres through the Polar pack ice, the ARKTIKA became the first surface ship to each 90°N latitude.

The ARKTIKA and the route followed to the North Pole are shown in Plate 6.3-3. In addition to three nuclear icebreakers (ARKTIKA, SIBIR and LENIN) the U.S.S.R. operates an extensive fleet of conventionally powered icebreakers. These include the Ermak class of three vessels, the most powerful diesel electric icebreakers in the world, which are used to extend the shipping season in the Northeast Passage.

6.3.1 ARCTIC TANKER DESCRIPTION

During their transit, Arctic tankers will be required to operate amidst first and second year ice ridges, sheet and floe ice, variously sized multi-year ice floes (some incorporating large multi-year ice ridges), icebergs, bergy bits and growlers, all of which will impose different design constraints upon the ship, her structure and her machinery.

The Canadian Government has enacted marine legislation controlling many features of the design and operation of Arctic shipping. These are the Arctic Shipping Pollution Prevention Regulations which control vessel entry into defined ice zones. Thus, at certain times of the year, only ships possessing the required Ice Class Certificate are allowed into those zones. The regulations are not, however, a design tool guaranteeing successful operation of ships, and do not relieve the naval architect of the responsibility of proper detailed design for the intended service. The proponents believe that the provision of "overdesign" within their ships will help to ensure successful operation.

While year-round transit of ships to the Beaufort Sea region by way of Prince of Wales Strait requires the granting of a Class 8 certificate, the proponents believe that this standard should be exceeded. Consequently, vessel design will comply with, and in many instances, exceed standards set for Class 10 icebreakers.

The CANMAR KIGORIAK, put into service by Dome Petroleum in 1979, is shown in Plate 6.3-4. This ship was designed as an experimental icebreaker to provide information needed to develop year-round Class 10 Arctic tankers. Ice trials in a variety of

conditions have confirmed the "in-ice" performance of the vessel. The comprehensive research program has yielded valuable information essential to the design of tankers for year-round operations.

6.3.1.1 General Characteristics

The following will provide a general description of the 200,000 tonne Arctic Class tankers proposed for full scale Beaufort Sea-Mackenzie Delta development. However, it should be noted that to service the early production plan, it is entirely feasible to use a "smaller" version of the Arctic Class 10 tanker. In this regard Dome is currently proposing the use of an 80,000 tonne tanker to transport early production from the Tarsiut field at a rate of approximately 3,200 cubic metres per day (20,000 BOPD). The design of this vessel will follow the same approach as that for the full scale production tanker.

A detailed description of the current design being considered for year-round Arctic navigation is given in this section. Specific design will vary from company to company, and also from ship to ship, as experience is gained with Arctic operations. Variations would lie principally in the areas of physical size of the vessel, the proportions of the main hull, the level of installed power, the type of propulsion system and fuel, and many other less significant factors (e.g. accommodation layout).

The tankers will be of all welded construction consisting of, from forward to aft, a fore-peak void space, a forward salt water ballast tank space, a midbody cargo space flanked by segregated salt water ballast tanks, fuel tanks, machinery spaces, and an aft void space and steering gear space. All accommodation will be forward of the cargo tanks and all the machinery and its operating spaces will be aft.

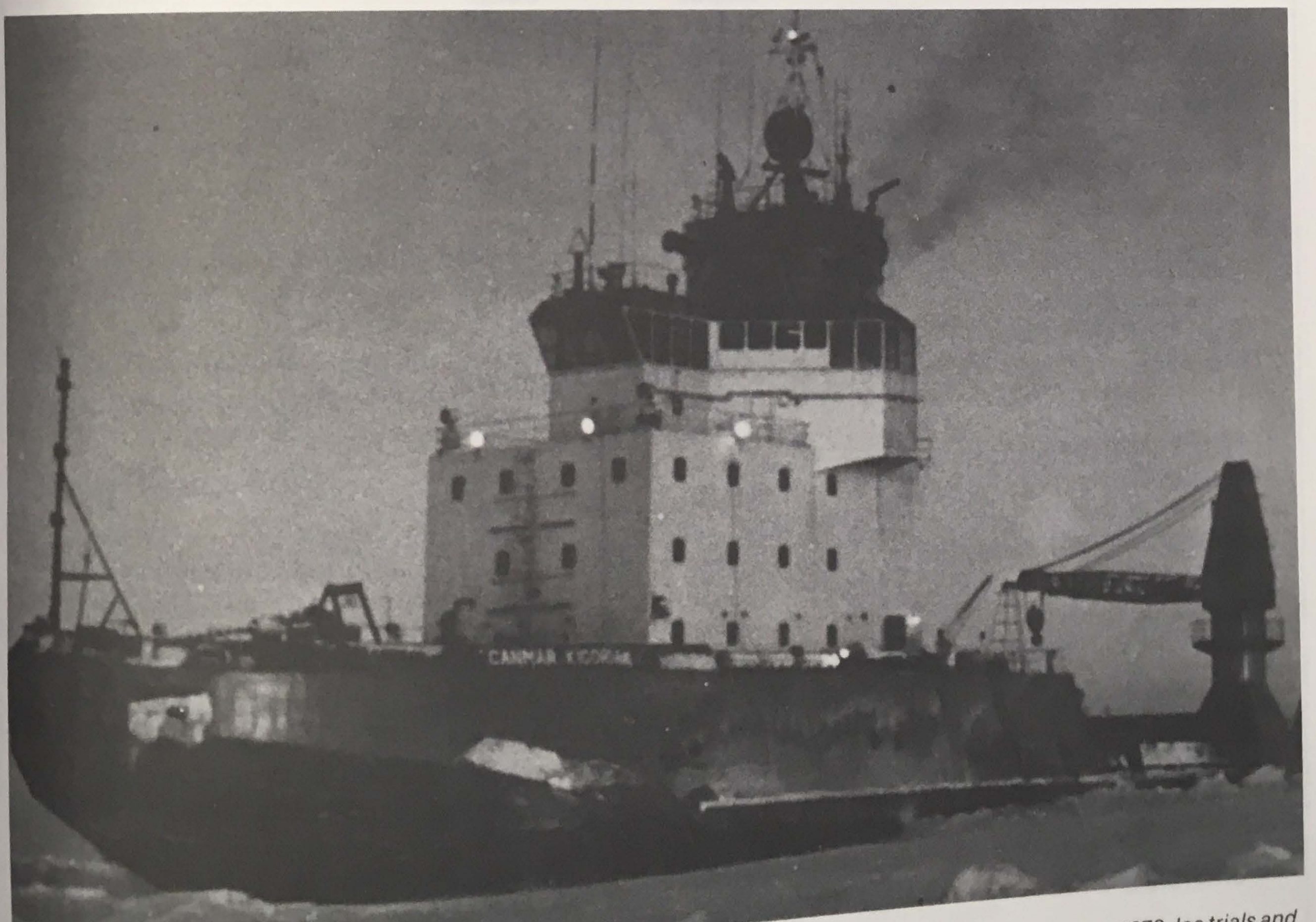


PLATE 6.3-4 *The CANMAR KIGORIAK, a Class 3 icebreaker, has been in service in the Beaufort Sea since 1979. Ice trials and operation of the KIGORIAK have provided valuable information which is being used in the design of Arctic tankers.*

The vessel's general characteristics [illegible] mately:

Length overall	390 metres
Length on waterline	370 metres
Breadth	52 metres
Depth	38 metres
Draft	18-20 metres
Displacement	300,000 tonnes
Installed power	112 MW (150,000 HP)
Cargo deadweight	200,000 tonnes
Crew	45
Fuel oil capacity	10-12,000 tonnes

These vessels will be similar in physical dimensions to large ships currently operating world-wide. In their 1980 statistical survey, Lloyds Register of Shipping recorded 709 commercial ships larger than 180,000 tonnes cargo deadweight and 144 ships above 250,000 tonnes cargo deadweight. Details of some of these large ships are provided in Table 6.3-1. The special features required for Arctic operation reduce the cargo carrying capacity of the Arctic tankers in relation to their size and power. For example, the ESSO PACIFIC, a tanker of approximately the same length, has a cargo carrying capacity of two and a half times that of the Arctic tanker. On the other hand, in order to cope with ice conditions, the Arctic tankers will have more than three times the installed power of the ESSO PACIFIC.

The distinctive features of the Arctic tanker are:

- Icebreaking capabilities to enable year-round travel through the Northwest Passage;

- A double-sided shell and double-bottomed hull structure to minimize the possible risks of oil spillage in case of collision or grounding;

TABLE 6.3-1

A SUMMARY OF THE SPECIFICATIONS OF SOME OF THE LARGEST SHIPS IN THE WORLD

Vessel Name	Length m	Depth/ Draft m/m	Cargo Capacity Tonnes	Power MW	No. of Propellers
Passenger Ships					
France now Norway	315	24.6/10.5	N.A.	119.4	4
Queen Elizabeth 2	294	17.1/ 9.9	N.A.	82	2
Cargo Vessels					
Arctic	209	15.2/10.9	28,000	11	1
Batillus Class	405	36 /28.4	559,000	48.5	2
Esso Pacific Class	407	31.3/25.3	508,000	33.6	1
Esso Caribbean Class	378.5	30.7/25.0	458,500	33.6	1
Manhattan	306	20.6/15.9	107,700	32	2
Lunni Class	164	12.0/ 9.5	16,300	11.6	1
Aircraft Carriers					
Nimitz Class	333	/11.3	N.A.	194	4
Enterprise Class	336	/10.9	N.A.	209	4
Kitty Hawk Class	319	/11.3	N.A.	155	4
Kiev Class	274	/10.0	N.A.	134	4
Battleship					
Iowa Class	271	11.6	N.A.	158	4
Icebreakers					
Arktika Class	136	/11.0	N.A.	56 Nuclear	3
Lenin	134	16.1/ 9.2	N.A.	33 Nuclear	3
Ermak Class	135	16.7/11.0	N.A.	26.5	3
Louis S. St. Laurent	112	13.1/ 9.0	N.A.	18	3
Polar Star Class	121	13.2/ 9.1	N.A.	45	3
Urho Class	105	13.6/ 8.3	N.A.	16.2	2 Fore 2 Aft
Proposed Arctic Tanker	390	38 /20	200,000	112	2 or 3

- Separate oil and ballast tanks;

- Oil tanks located inboard, beyond the theoretical limits of the worst damage assumptions for ship bottoms and sides provided by the International Maritime Consultative Organization (I.M.C.O.);

- Multiple, independent propulsion systems and rudders;

- Constant deep draft operation capability to reduce ice loads on propellers and rudders;

- Independent, deep-well oil pumping systems for each tank, to both reduce in-hull piping and for better and safer cargo handling;

- Inert gas system for oil cargo tanks to reduce fire and explosion hazard;

- Ability to pump and contain oil from any compartments, if damaged, to undamaged ballast tanks;

- Sophisticated navigation and collision avoidance systems using the integration of multi-sensor inputs;

- Excellent vessel manoeuvrability at full power and maximum rudder angles;

- "Real-time" bridge readout of hull-mounted instrumentation to monitor stresses in critical parts of the hull; and

- Forward-mounted navigation bridge for best forward visibility.

Figure 6.3-2 illustrates some of the differences between Arctic tankers and conventional tankers.

6.3.1.2 Hull Form and Design

To fulfill the icebreaking and oil cargo functions, the icebreaking tanker will be a double-hulled structure built to comply with, or exceed, the appropriate Arctic Class standard specified in the Arctic Shipping Pollution Prevention Regulations.The hull will be built to withstand the impact of ramming into ice, crushing from ice forces, and induced stresses caused by the vessel "beaching" on a multi-year ice floe.

The hull shape of the icebreaking tanker will incorporate an efficient icebreaking bow with reamers to ensure that the channel cut in the ice is wider than the ship in order to allow greater manoeuvrability and reduce hull friction. The stern shape will be specially designed to deflect ice away from the propellers. The design includes a short spoon shaped bow, straight sides and a unique underwater aft-end shape to reduce ice ingestion by the propellers.

In any icebreaker, the bow portion of the vessel must be structurally sound, since it receives the largest and most consistent impacts and loading from the ice. Extra strengthening is added by increased shell plating thickness and intermediate support members to withstand the high localized ice pressures exerted on the hull.

The resulting structure consists of very thick shell plating (approx. 70 millimetres) supported by closely spaced frames (approx. 400 millimetres) supported in turn by stringers, webs and decks. This energy-absorbing matrix will cover the full length of the sides of the hull. The cargo tanks, fuel tanks and engine rooms will also be backed by a second longitudinal bulkhead. The resulting structure of a "box within a box" will be extremely strong. It is estimated that the extra heavy hull over the ship's length, together with the double-hull configuration, will result in a hull girder strength about three times stronger than that of a conventional ship.

In the case of a mishap, not only would it be much more difficult to puncture the strengthened hull, but in the event of such a failure, damage would be very much less intensive and localized. The cargo would be safely contained behind the heavy strengthening within the double skin.

Results of Arctic Tanker Risk Analysis studies (Bercha and Associates, 1978, 1981) show that, in a ramming situation, the proposed ice-strengthened Arctic tanker hull is approximately fourteen times less likely to be penetrated than a conventional ship. In the event that an Arctic tanker should collide with an iceberg, some damage would be caused, but it is very unlikely that the cargo tanks within the double hull would be ruptured. Further, the use of an inert gas system and segregated ballast tanks virtually eliminates the risks of explosion.

The oil cargo tanks will be surrounded by side-tanks and a double bottom reserved for seawater ballast, providing a major increase in structural strength, and allowing control of any out-flow of oil in the unlikely event of a major accident. Oil containment is described in Section 6.3.1.6.

6.3.1.3 Propulsion System

Preliminary studies and icebreaker experience have confirmed that, for year-round Arctic operation, the

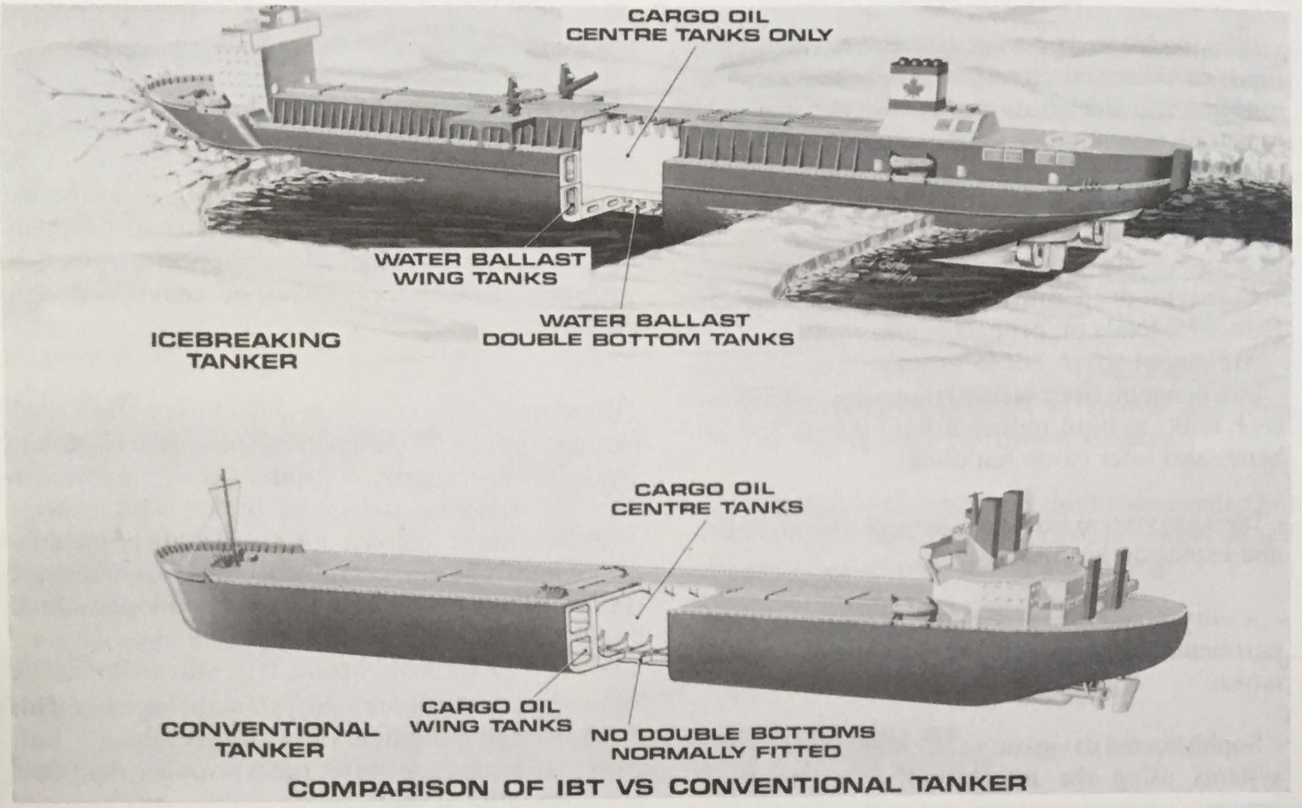


FIGURE 6.3-2 *Arctic tankers will be built with many special features not found in conventional tankers. These include a Class 10 icebreaking capability, separate oil and water ballast tanks and a double-bottomed hull to minimize the risk of oil spillage in the event of an accident.*

propulsion system must be capable of withstanding rapid changes in power requirements, many power cycles, from full power ahead to full power reverse, changes in direction, absorption of substantial thrusts from ice-ramming, and severe torque fluctuations induced by ice milling.

To obtain these characteristics, the proponents have considered many propulsion and transmission systems. They have concluded that two engine types and two transmission systems are viable.

These engine types are medium or slow speed diesel engines, or gas turbines. The diesels offer very low specific fuel consumption while the gas turbines offer a very high power output per unit of space required. Both have an extensive history of successful marine operation.

The transmission systems are direct drive, where the engine drives directly through a speed reducing gearbox to a controllable pitch propeller; or an electric system where the engine is coupled directly to an electrical generator whose power (AC) drives an electric motor connected to a fixed pitch propeller. A mechanical drive transmission system offers low energy losses but is large and heavy. The electrical system is expensive but technically proven by most icebreakers of the world.

One alternate Arctic tanker machinery package, as designed by Dome, includes two independent propulsion systems. These will include three medium speed diesel engines per shaft connected directly to a gearbox driving the propeller shaft and a controllable pitch propeller. Clutches, adjusted to slip at a certain overtorque will be fitted to protect the gearbox and the diesel engines from shocks and peaks in ice torque.

The Arctic tanker will be designed to develop 56 megawatts (MW) per shaft for a total of 112 MW and should be able to pass unassisted through all ice in the Northwest Passage throughout the year. It should be capable of achieving 6 knots in 3 metres of level ice, and have a maximum open water speed of about 23 knots.

The controllable pitch design of propellers allows the direction of propeller thrust to be changed very quickly. This makes it possible to obtain reverse thrust with a minimum of delay and without stopping the rotation of the propellers. These propellers

give high efficiency and result in a faster response time for manoeuvring. Thus it will be possible to stop an Arctic tanker in about 1 kilometre in open water compared to about 5 kilometres for a conventional tanker.

As proposed, each propeller will be protected from milling ice by a nozzle, that is, a short tube surrounding the propeller (Plate 6.3-5). These nozzles will also provide a 25 to 30 % increase in thrust.

During the detailed design of their specific vessels a final decision will be made on the engine and transmission system that best suits their individual needs.

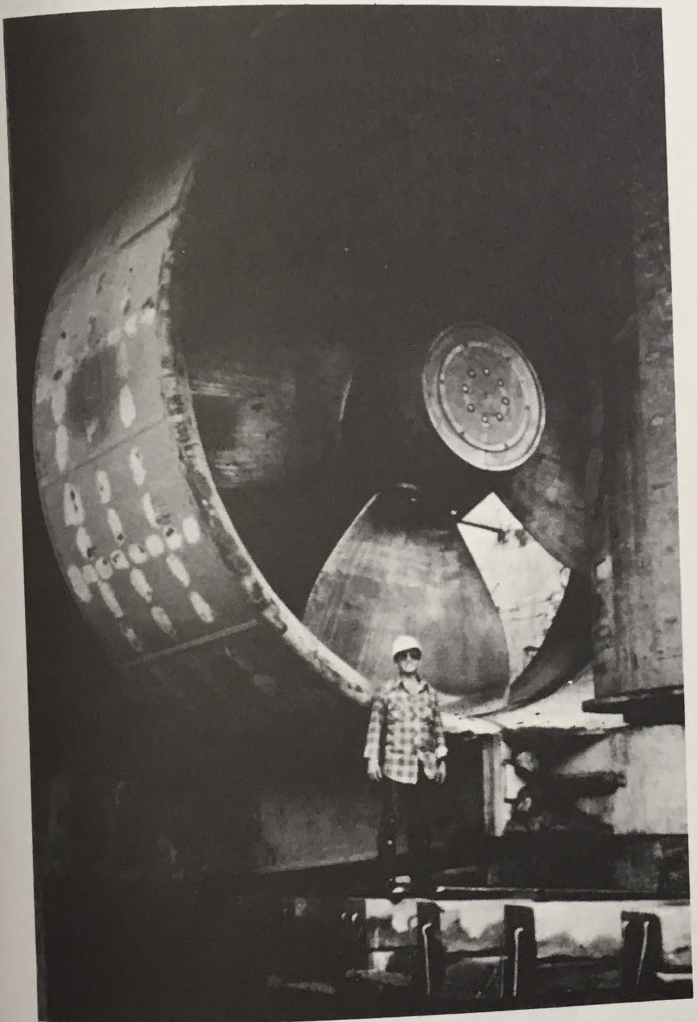


PLATE 6.3-5 *The propellers of the Arctic tankers will be protected from milling ice by a nozzle surrounding them as is currently used on the KIGORIAK icebreaker.*

6.3.1.4 Fuel Storage

The tankers will have a diesel fuel capacity of approximately 10,000 to 12,000 tonnes, permitting 30 days travel at full power. The fuel tanks will be located completely inside the double hull and directly forward of the engine room. Fuel consumption will vary seasonally and will depend on the final installed power. In winter, most of the fuel cargo will be consumed on each trip, while during summer a lesser amount would be used. The heavier winter fuel demand is due to icebreaking and the slightly longer distances involved with the winter routes. The tankers will be capable of carrying enough fuel for the return voyage but could top up their fuel tanks at the northern terminal if required.

6.3.1.5 Waste Management System

Sewage generated aboard the tankers will be treated prior to discharge and sludge will be incinerated on board. Grey water, from the galley and laundry facilities will be treated for solids and grease removal prior to discharge. The grease will be incinerated as will most solid waste. Non-combustible waste will be compacted and stored onboard for disposal at the southern terminal.

The Federal Arctic Waters Pollution Prevention Act specifies conditions under which oily wastes can be discharged into Arctic water, as do the international standards set out by the Inter-Governmental Maritime Consultative Organization (IMCO). To comply with these requirements, the Arctic tankers will be fitted with oil-water separators to treat oily bilge, whereafter the oily waste will be transferred to 'slop' tanks, which must be sized to accommodate at least 1.5% of the cargo deadweight tonnage. The wastes can then either be burned, or stored until the ship reaches its southern terminal, where it will be offloaded.

6.3.1.6 Cargo Containment

The tankers will be fitted with about fourteen oil containment tanks, located within the inner hull, having a total capacity of about 230,000 cubic metres (203,000 tonnes) of oil.

If, during a cargo voyage, the outer hull were breached while the inner hull remained intact, the empty ballast tanks within the double skin would flood with sea water. Even in the event that two adjacent compartments were flooded, the ship would safely remain afloat in stable equilibrium. In addition, no corrective trim action would be required by the crew. If both the outer and inner hulls were breached from below, i.e. as a result of grounding, oil outflow would still not likely occur. Model tests show that it is possible to contain outflow from the oil cargo tanks within the space between the outer and inner hulls. Sufficient volume for this purpose is provided in this space. Any buoyancy lost can be regained by introducing controlled volumes of compressed air above the oil level in the outer side tanks (Figure 6.3-3). This will depress the air/oil interface and the cargo pumps can be used to empty the tank, with the compressed air gradually replacing pumped oil. The oil will be transferred to a safe compartment elsewhere in the ship with very little loss of buoyancy.

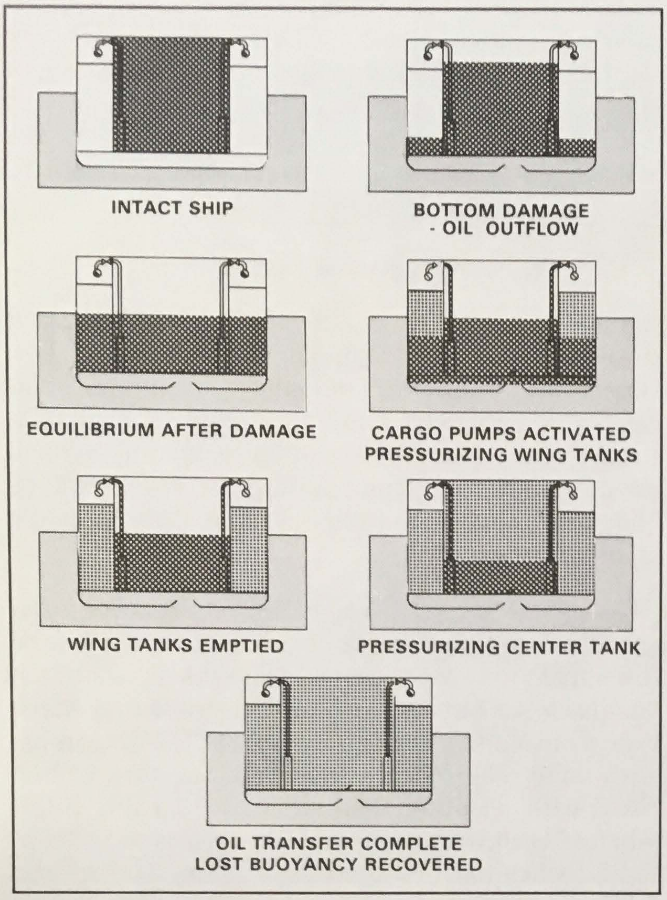


FIGURE 6.3-3 *The cargo containment system of the Arctic tankers will be designed in such a way that even if the hull were damaged in an accident, the ship would remain afloat in stable equilibrium and no oil would be spilled. Oil from damaged tanks would be pumped into another compartment.*

On conventional ships, the cargo oil handling system has been determined to be a source of mishap, due to mechanical and/or operator errors. A system has been chosen for cargo movement consisting of submersible pumps in each cargo tank, which transfer liquid up out of the tank into transfer piping. With this system, tanks may be individually pumped thereby eliminating in-hull piping, inaccessible remote control valves and a pump room, with their associated risk of explosion.

6.3.1.7 Manoeuvrability

The Arctic tankers, with their multiple propellers, twin rudders and fore and aft transverse thrusters will have significantly improved manoeuvring and stopping abilities compared to their open water counterparts. Most conventional tankers of comparable size to the icebreaking tankers have only one propeller, with installed power of about 30 MW. Hasty astern manoeuvres by such vessels often result in unpredictable trajectories due to loss of directional stability. Because of this, the preferred manoeuvre in an emergency is to turn the vessel broadside on through 90°, thus rapidly reducing the forward movement.

Slow speed manoeuvres for all ships are improved by the use of bow and stern transverse thrusters. In 1976, the United States Coast Guard demonstrated, with the 45 MW triple screw icebreaker POLAR STAR, that open controllable propellers can be made operational in Arctic conditions. The characteristics of that propulsion system were: the ability to rapidly change the direction of propeller thrust (by changing the blade angle of attack); the ability to avoid stopping the propeller during manoeuvring; and the ability to efficiently use the input power over a wide range of operating conditions.

With multiple screws, the thrusters on one side of the vessel can be put hard astern while those on the opposite side are put hard ahead. This results in a very high turning moment being applied to the vessel in addition to that imposed by the rudders. Even without changing the direction of propeller thrust, the vessel's twin rudders immediately behind, and consequently in, the propeller wash will give the vessel excellent open water turning capability.

The manoeuvring and stopping characteristics of the Arctic tankers will also be improved by other features incorporated into the propulsion system, namely: the much higher power (about 4 or 5 times conventional), and the much quicker response time of the engine controls.

The higher power, required to develop the very high thrust necessary to push the ship through up to 3 metres of Arctic ice, coupled to a propeller design with improved astern performance (necessary for backing up in very thick ice and ridges), makes a very high reverse thrust possible. This is estimated to be up to 10 times that of a similar conventional tanker.

The quick response time, of only about 15 seconds to apply full reverse thrust, is an inherent design feature in both the controllable pitch propeller system and the electrical transmission system. This response time is about 6 times faster than that of a conventional tanker's steam turbine plant.

The Arctic tankers will also be fitted with an air bubbler system; this system supplies low pressure, high volume air to a series of nozzles in the side shell below the ice line. The bubbles moving to the surface entrain water and carry it through the hull-ice interface, thus providing lubrication. Additionally there is a clearing action as ice is moved away from the ship's hull, aiding low speed and berthing manoeuvres.

6.3.2 TANKER OPERATIONS

The use of icebreaking tankers for year-round oil transportation from the Beaufort Sea to southern markets brings unique and challenging problems to

the vessel's operators. While there is a huge body of data and expertise available world-wide for conventional (open water) tanker operations, there is none for Arctic operations. As described, in response to Arctic conditions and the need to protect this important environment from oil spills, naval architects are designing ships with unsurpassed safety features. In this section, the operational systems and procedures to be used for these Arctic tankers are described.

6.3.2.1 Tanker Loading and Mooring Arrangements

A number of terminal concepts are being considered for the loading of oil into Arctic tankers. The two primary northern terminal concepts are the Arctic Production and Loading Atoll (APLA) and the Single Point Mooring Terminal.

An Arctic Production and Loading Atoll is an artificial island which will provide an internal protected area of stable ice cover, within which the tankers will dock. Shown in Figure 6.3-4 is one APLA concept. Further details of APLA concepts are discussed in Section 4.3. Prior to the arrival of an empty tanker from the south, the ice cover will be broken up by icebreaking tugs. These tugs will then also assist the tankers in docking manoeuvres if required.

The tankers will be moored to quick release mooring hooks capable of holding them in place under any anticipated wind conditions. Both the vessel and shore control rooms will be able to initiate quick release of the mooring hooks thus allowing the vessel to vacate the berth in about 6 minutes in case of an emergency. To aid in such an emergency, at least one tug will be on standby at all times.

For loading crude oil, present world practice is to use either articulated swivel arms or counter-weighted flexible hoses to bridge the gap between fixed onshore piping and piping on the vessel's deck. Either of these methods may be used to load oil into the tankers.

Based on a required pumping time of about 12 hours to transfer the oil, the design pumping rate will be about 17,000 tonnes per hour. Four swivel arms, each about 400 millimetres diameter, will be required to do this. The pumping time could be reduced further if desired by increasing the diameter.

It is possible that a Single Point Mooring Terminal could be used for the loading of Arctic tankers. Unlike an APLA, this would not be a multi-purpose structure and would not incorporate a protected harbour. Oil storage facilities could be located on production islands or on a storage island in shallower water and be connected to the loading terminal by subsea pipelines (see Section 4.5.4.2). The loading terminal would be located in deeper water where tankers could moor.

A study has been made of a possible design for a Single Point Mooring Terminal (Swan Wooster Engineering Co. Ltd., 1982) the structure of which is

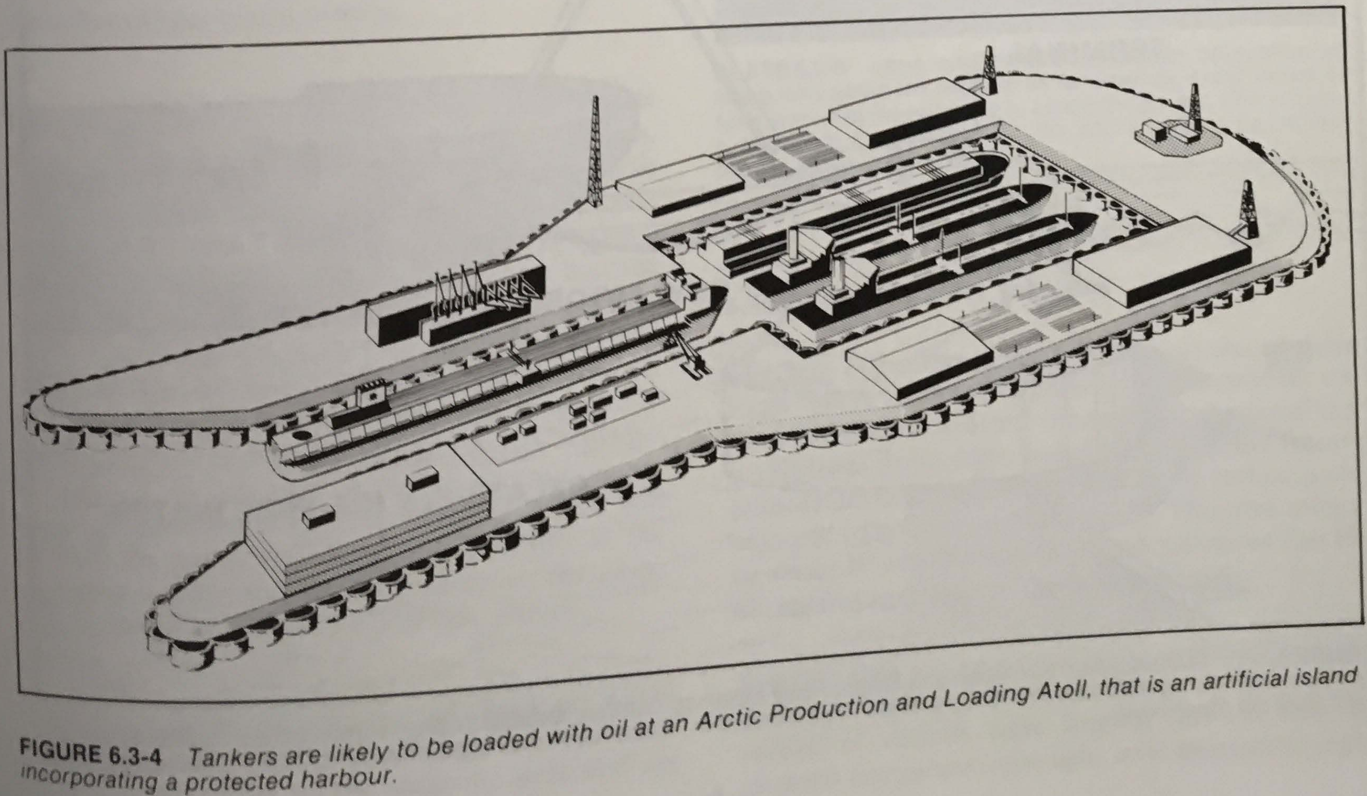


FIGURE 6.3-4 *Tankers are likely to be loaded with oil at an Arctic Production and Loading Atoll, that is an artificial island incorporating a protected harbour.*

similar in concept to the caisson islands described in Section 4.3.6. The proposed structure (Figure 6.3.5) has a steel shell which would be ballasted to the seafloor, first with water and then, when operational, with sand. The circular space within the shell would be filled with dredged sand. The loading arm would pivot about the centre of the structure and the tankers would approach from the leeward side in order to protect the bow from ice movement. If the direction of ice movement changed during loading, the loading arm could be disconnected and the tanker repositioned.

6.3.2.2 Safety

While the final responsibility for all the vessel's operations lies with the master, certain operational limits will be pre-defined in order to reduce the potential for human error. Operational limits will be determined based upon proven experience and will include for example:

- A maximum allowable speed for open water when no floating ice is present;
- A maximum allowable speed when ice is present;
- A maximum allowable speed in low visibility;
- The vessels are not to approach any shore or static floating structure, other than at the terminals, to within 40 metre water depth or 10 kilometre distance;
- The icebreaking tanker is to keep a constant radar watch on at least two frequencies;
- The vessel is to report daily to the head office regarding the status of the ship and all her equipment, the surrounding environmental conditions, ice, wind, waves, visibility etc., and her expectations of conditions and performance for the next 24 hours;
- A constant rotation of officers and crew with regular and prescheduled periods of time off.

In addition to physical operational limits, it is emphasized that the human factor is the key to safe and effective operations. Thus, emphasis will be put on hiring personnel with skills in tanker or icebreaker operations. In order to achieve high safety standards, a training program will be carried out continuously for all people at all operational levels. The Inter-Governmental Maritime Consultative Organization has set new stringent standards governing officers' qualifications and ships' safety equipment. These are enforced by the Canadian Coast Guard.

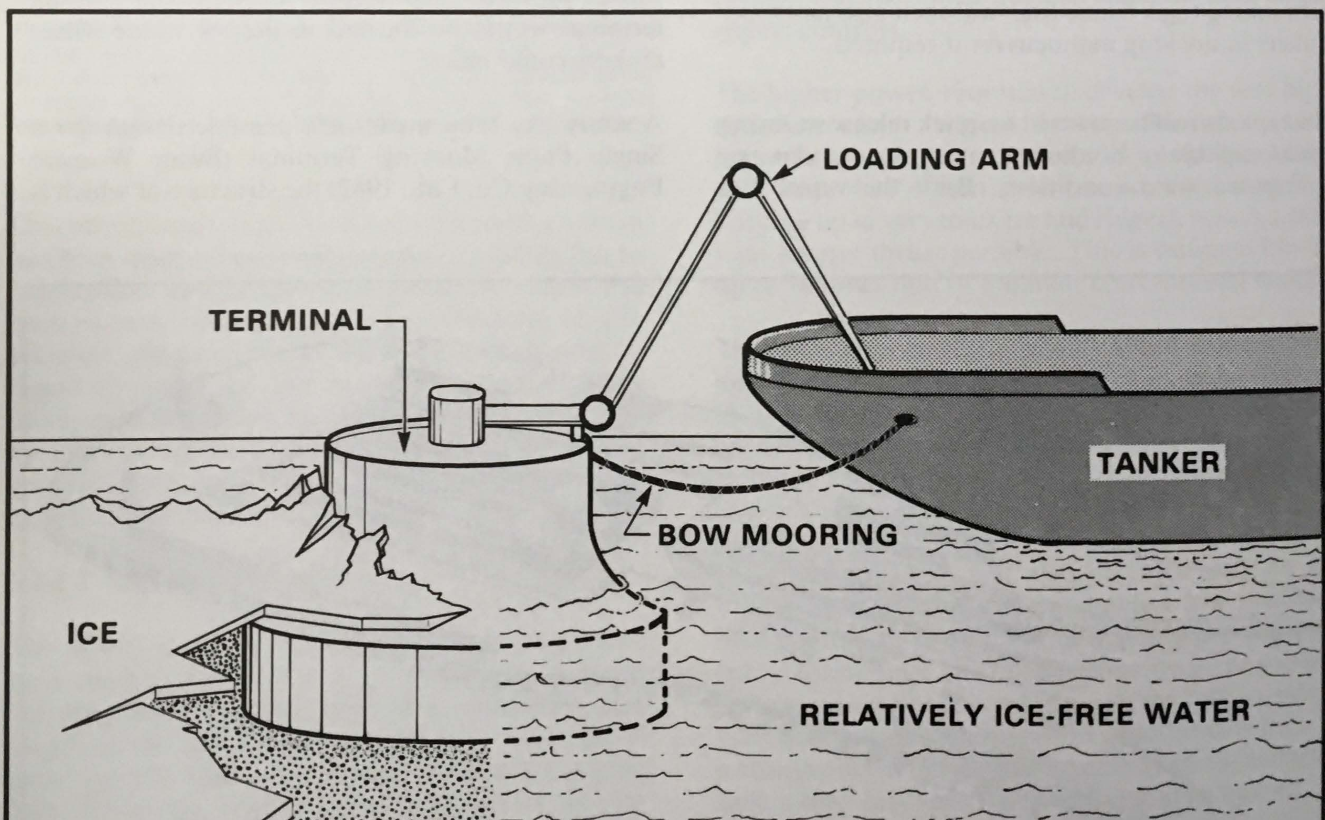


FIGURE 6.3-5 *Tankers could be loaded at a Single Point Mooring terminal located in deep water and connected by subsea pipelines to oil storage facilities in shallower water. The tankers would be loaded on the leeward side of the terminal to protect them from ice movement.*

Stringent maintenance and preventive maintenance programs will be carried out to ensure the ship's safety. All safety precautions available to prevent the build-up of static electricity, the ignition of vented vapours, overstressing of tank and main girder structures and loss of stability, will be built into the design of the ship. There will be strict enforcement of fire prevention measures, including control of smoking; hot work such as welding or burning; blowing tubes or funnel uptakes; radio or radar transmission, except VHF frequencies; and use of power tools or hand tools outside machinery spaces other than those designated as "non-sparking."

Hydrographic surveys along the proposed route are being conducted to ensure safety of operations. Only portions of the route have been surveyed in detail but extensive work is planned by the Canadian Hydrographic Survey and if necessary by industry. Due to the size of the Arctic tankers and the potential consequences of an accident, dense surveys are required in areas of known possible hazards, for example the area of uncharted underwater pingos in the southern Beaufort Sea.

6.3.2.3 Navigation and Communication Equipment

The navigation equipment planned for the Arctic tankers will meet or exceed the requirements of the Arctic Waters Pollution Prevention Regulations. The tankers will be fitted not only with the required navigation and communication equipment, but also with a number of specialized devices.

Each tanker will be capable of receiving signals transmitted by satellites in polar orbit. These signals, available approximately once every 30 minutes north of latitude 70°N, will be analyzed by computer to fix the ship's location. A new satellite system (Navstar) which may be in service when the tankers become operational, will provide continuous information of a very high order of accuracy for fixing latitude and longitude. This will be very valuable in Arctic navigation. Receivers for medium and long range radio positioning aids such as Decca and Loran C will also be installed. In addition, a highly accurate short-range (28 kilometres) radio positioning system will be fitted for use in approach and departure at the loading terminals. Navigation systems are discussed in more detail in Section 5.4.3 of this volume.

Two gyro-compasses, a master and a back-up, will be installed in the vessels. Gyrocompasses are unaffected by proximity to the magnetic pole and are therefore essential in the north.

The icebreaking tankers will also be equipped with a collision avoidance system. This will monitor other ship traffic by the use of radar and will plot vessel movements on an automatic plotting table.

6.3.2.4 Shore-Based Navigational Aids

Since, to date, all marine traffic has been limited to the summer season, in some parts of the route, the existing navigational aids are inadequate for year-round use to the standards required for Arctic tankers. Additional shore-based navigational aids currently in the planning stage will provide for the safe passage of icebreaking tankers and any other ships that transit Arctic waters outside the present navigational season. For example, long range radar beacons may be installed at key points such as landfalls after crossing open expanses of water and areas where very accurate navigation is essential. The former would include, for example, the entrance to Lancaster Sound (Plate 6.3-6) and both the southern and northern entrances to Prince of Wales Strait (Plate 6.3-7).

PLATE 6.3-6 *Long range radar beacons may be installed at key points along the route to be followed by Arctic tankers, for example at the entrance to Lancaster Sound. This photograph is of Bylot Island on the south side of Lancaster Sound.*

6.3.2.5 Near Field Ice Detection

The safe operation of tankers on portions of their route where ice is expected is largely dependent on the crew's ability to assess the type and severity of the ice features around the vessel and along her future path. Of most immediate concern is the tactical area adjacent to and ahead of the vessel. This area might be about 10 to 50 kilometres ahead and about 5 to 10 kilometres each side of the intended track.

Systems that are presently being evaluated for ice detection within this area include forward search radars, of various wave lengths; forward looking infrared equipment; low-light level televisions; high

PLATE 6.3-7 *It is proposed that tankers will carry crude oil from the Beaufort Sea through the Northwest Passage to the East coast. It is also possible that they might operate through the Bering Strait and around Alaska.*

intensity light sources; and a searchlight array illuminating the area ahead of the vessel. Figure 6.3-6 is an artist's conception of a tanker using a potential hazard detection system to operate through ice.

A tactical system will be designed to compile information from these sources and give the ship's crew a high quality, on-line, all weather picture of the area in front of the ship. A hazard detection system could automatically plot the ship's course relative to the adjacent coastlines, islands, reefs and other hazards, which would already be stored in its memory (see Section 5.4.2). The information gathered would be used to plan the ship's immediate route and power level. Areas with a high density of icebergs will be avoided but the ship's master will still have to be prepared for the possible presence of major icebergs. The ice detection system, however, will allow him to approach these hazards with caution. The master should have ample time to consider all the facts and make the best use of the exceptional power and manoeuvrability of his ship.

6.3.2.6 Route Planning and Traffic Management

The tankers will form an integral part of the Remscan system. This system for monitoring weather and ice conditions, providing communication links and strategic route planning is described in Section 5.4. All data such as ice conditions, wind speed and direction, iceberg tracking, and the location of ships, will be compiled at a shore-based strategic operations centre. Information will be relayed to the ships to assist in selecting an optimum route, power level, etc. In turn, information on the ship's progress and surrounding ice conditions will be continuously revised and transmitted back to the centre. The centre will also provide information to the tankers on the location of other ships in their area.

A valuable source of information to any ship operating in ice is observation from other ships in the area. There will thus be frequent communication between the tankers, about 16 of which may be operating along the route by the year 2000 if an intermediate oil production rate is pursued (see Chapter 3). In addition, by 1987 there may be two LNG tankers of the Arctic Pilot Project operating along the same route, transporting liquid natural gas from Bridport Inlet on Melville Island to a terminal on the east coast of North America.

By 1986, when the first oil tanker enters the Beaufort Sea, there could be about 90 vessels operating in the Region in support of drilling operations. They will range in type from drillships and icebreakers to dredges and barges, none of them as large or powerful as the tankers, but all of them requiring a vessel monitoring system. By the year 2000 the total number of vessels operating in the Beaufort Region is estimated to increase to approximately 167 (not including tankers) for an intermediate oil production rate.

Within the vessel monitoring zone, particularly during times of ice, a network of fixed routes will evolve along which the ice is broken at regular intervals. This will simplify traffic management to some extent, while at the same time demanding a high degree of caution as vessels meet or overtake each other. Speed in ice, however, will be slow and therefore risks of collision will be reduced.

At the northern tanker terminal, a traffic separation system will be used to control the movement of tankers and other shipping in the vicinity. Recent statistics (Lloyd's Shipping Economist, 1981) have shown that traffic separation systems have vastly reduced collisions in northwest European waters, for example in the Dover Strait, in the English Channel off southwest England and in the southern North Sea. Off the coast of northwest Europe, collisions between ships steaming in opposite directions used to constitute about 80 % of total collisions; these are now almost negligible within the limits of the separation schemes.

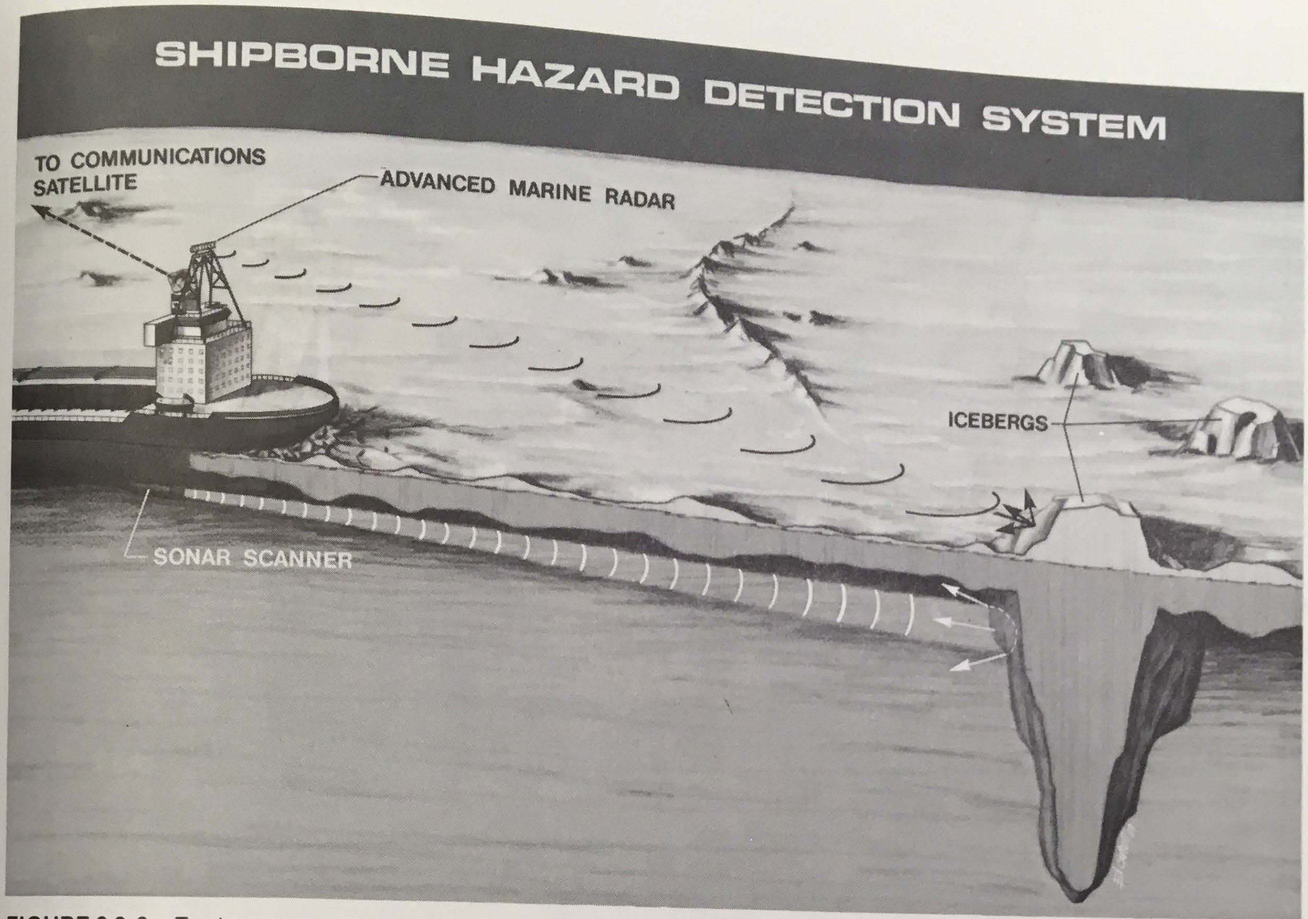


FIGURE 6.3-6 *Tankers operating through the Northwest Passage will be equipped with the most advanced communication and navigation systems. Radar and sonar scanner systems will be used to provide up to the minute information on ice conditions and hazards ahead of the ship.*

6.3.3 SHIPPING CORRIDORS

The primary shipping corridor proposed for tankers operating from the Beaufort Sea area to the east coast of North America follows Amundsen Gulf, Prince of Wales Strait, Parry Channel, Baffin Bay, Davis Strait, and the Labrador Sea (Figure 6.3-7). Due mainly to depth requirements, this is considered by the proponents to be the most viable route. An alternate route to the east would proceed through M'Clure Strait and then return to the remainder of the primary route. In addition, over the longer term, oil could be transported to the west around Alaska and through the Bering Sea.

Within the proposed corridor there is sufficient width available for selection of a course to ensure safety of navigation within the ice cover. By taking advantage of the leads and cracks that occur naturally in any ice sheet the tankers will be able to reduce the impact of the ice on their movement and improve their transit speed. The route followed may also vary seasonally in order to avoid disturbance of marine wildlife at critical times. (For more details on bathymetry and all relevant aspects of the eastern shipping corridor, the reader is referred to Volume 3B).

Alternative routes were considered but were rejected for a variety of reasons:

- due north from the Mackenzie Delta, along the west coast of Banks Island, through M'Clure Strait and thus into Parry Channel; westerly winds blow polar pack ice from the Beaufort Sea into this strait creating severe conditions in most years;

- by way of the channels south of Victoria Island then via M'Clintock Channel or Peel Sound to Parry Channel; this route is too shallow for the large tankers being considered since the Dolphin and Union Strait is only 14 metres deep; or

- by following the proposed route to Parry Channel then south through Prince Regent Inlet, Fury and Hecla Strait, Foxe Basin, and Hudson Strait to the Labrador Sea; the deep part of the Fury and Hecla Strait is too narrow to be navigable by large ships; and

- around Alaska, through the Bering Strait, to British Columbia; this route is presently used to sealift some material into the Region during the very short open water season and will become more active for this purpose as development proceeds.

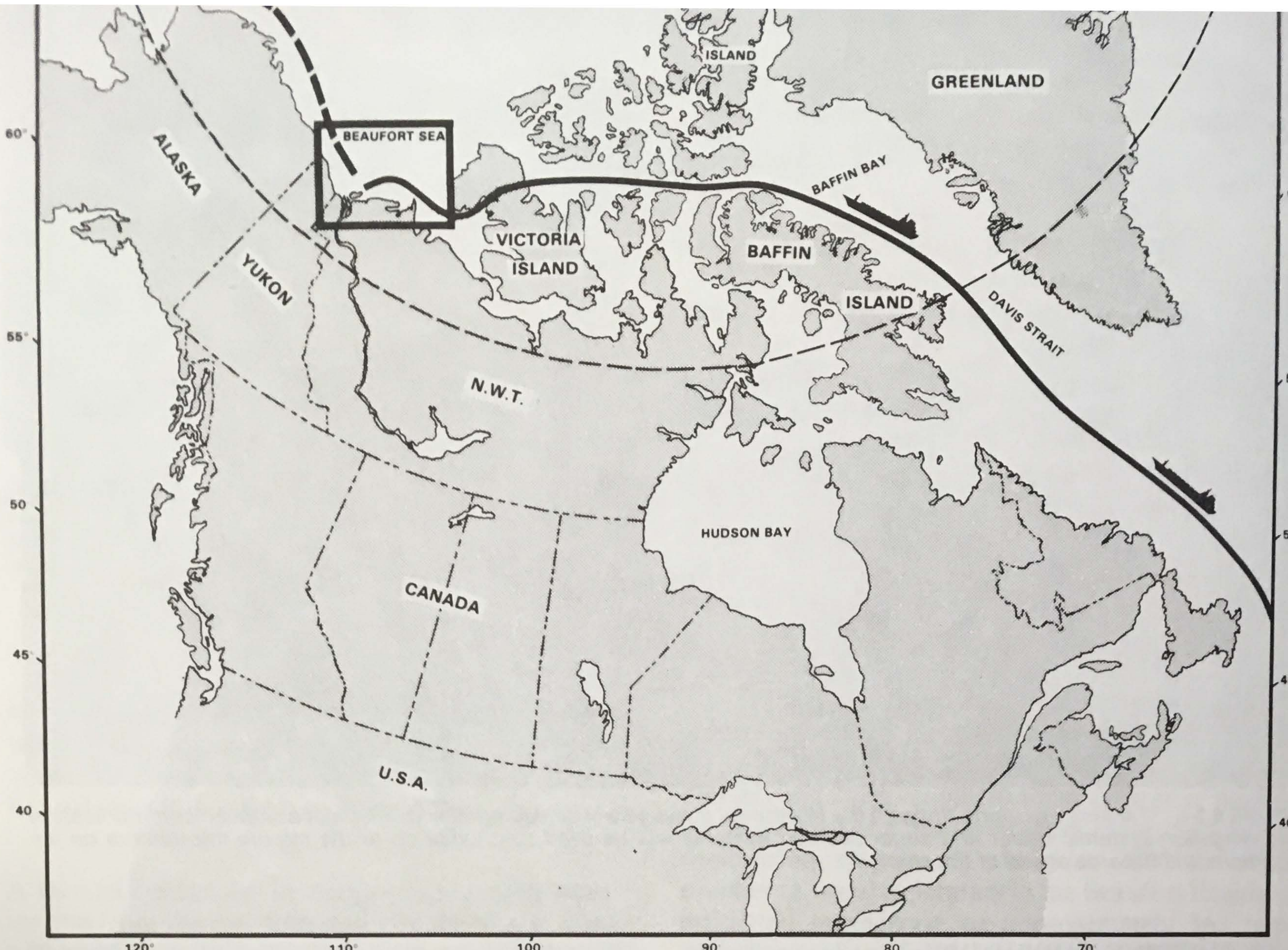


FIGURE 6.3-7 *It is proposed that tankers will carry crude oil from the Beaufort Sea through the Northwest Passage to the East Coast. It is also possible that they might operate through the Bering Strait and around Alaska.*

The corridor to be followed by the tankers from the Beaufort Sea to the Labrador Sea at 60°N covers about 4,400 kilometres. This is briefly described in the following sections, for which purposes it has been divided into seven segments:

- Beaufort Sea;
- Amundsen Gulf;
- Prince of Wales Strait;
- Viscount Melville Sound and Western Barrow Strait;
- Barrow Strait and Lancaster Sound;
- Baffin Bay; and
- Davis Strait and the Labrador Sea.

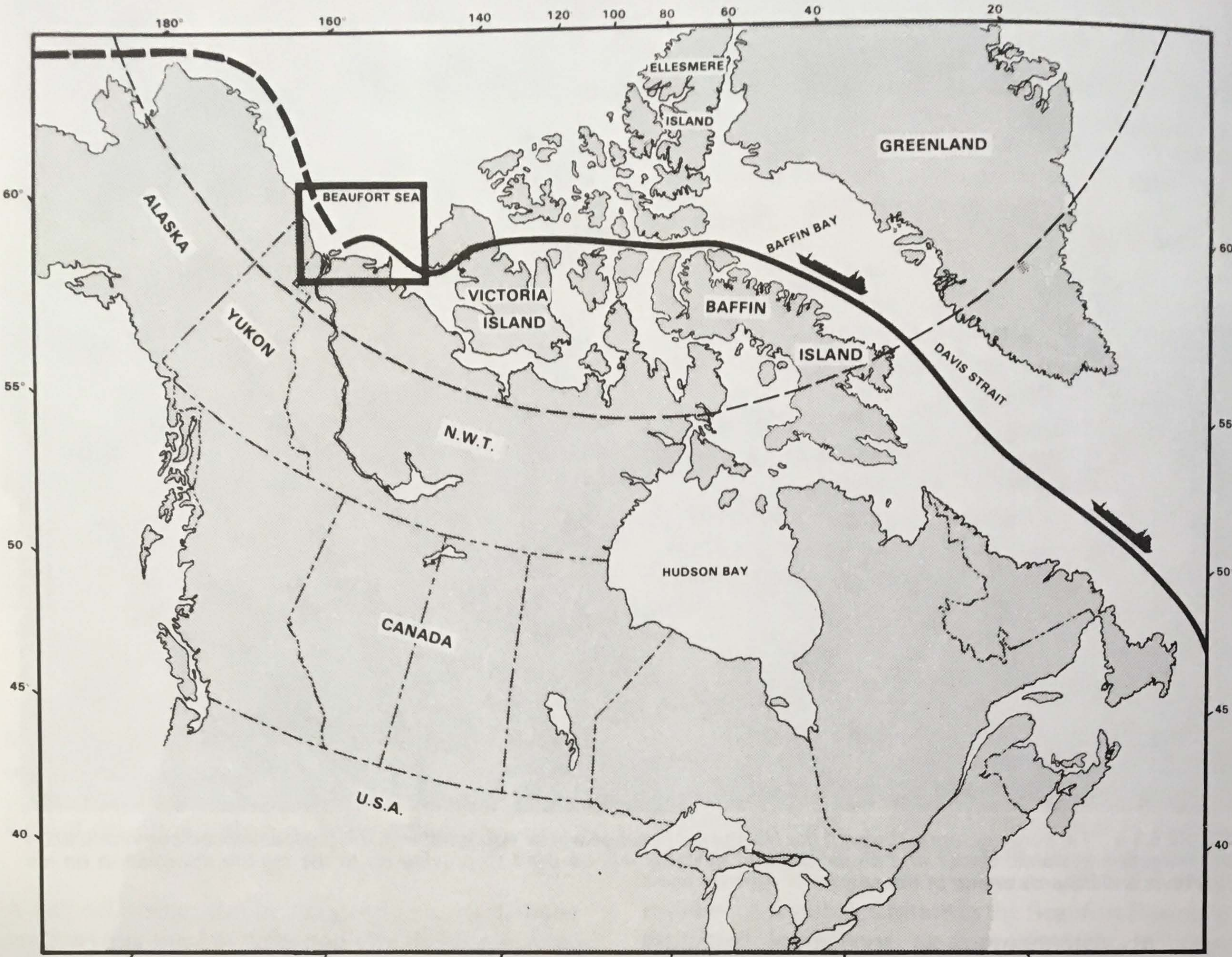
Further information on this subject is available in Volume 3B.

6.3.3.1 Beaufort Sea

136°W to Cape Bathurst (about 280 km)

The western sector of the shipping corridor from the Beaufort Sea-Mackenzie Delta Region is shown in Figure 6.3-8. The ice in the Beaufort Sea is dynamic and variable, depending on the retreat of the polar pack in summer, the severity of the winter, and the direction and strength of coastal winds.

In winter, there is a dynamic, principally first-year ice cover, reaching a maximum thickness of about 1.9 metres. By operating in shallower water close to the 30 metre depth contour, the probability of encountering multi-year ice will be significantly reduced. First-year ridges will be in the order of 10 per kilometre. However, even in mid-winter, there should be some cracks and leads parallel to the shore.



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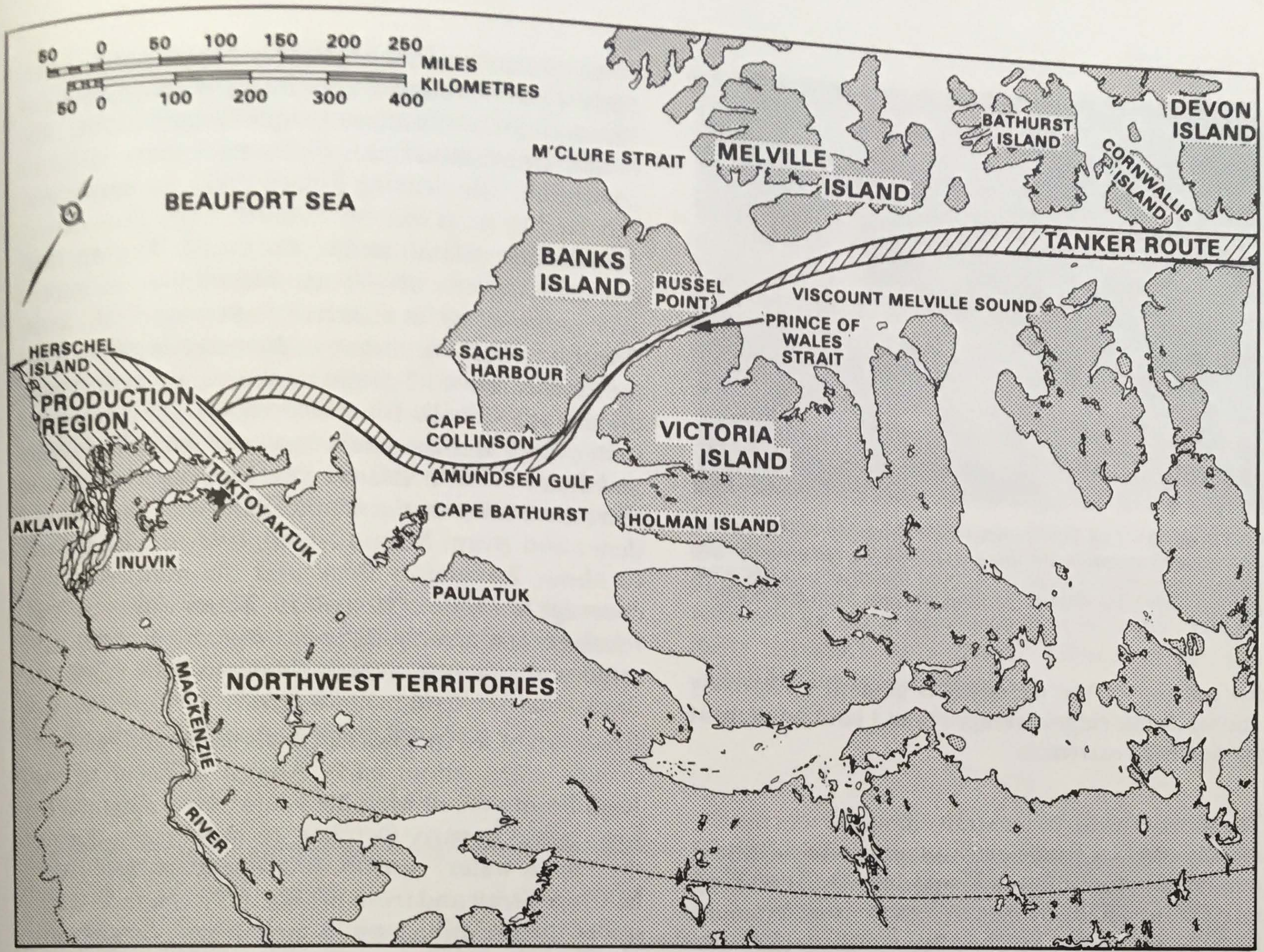


FIGURE 6.3-8 *This map shows the proposed shipping corridor from the Beaufort Sea, through Amundsen Gulf, Prince of Wales Strait and Viscount Melville Sound.*

Shore leads from Cape Bathurst to Herschel Island usually open in March with the remainder of the ice cover on the ship route clearing rapidly after mid-May.

Freeze-up is normally complete by late October although, due to movements within the pack ice, extensive patches of open water and thin new ice occur well into November.

6.3.3.2 Amundsen Gulf

Cape Bathurst to Cape Collinson (about 325 km)

In this region the ice cover is predominately first-year with only low concentrations of multi-year ice moving in from the Beaufort Sea or Prince of Wales Strait. West of a line from Nelson Head to Cape Bathurst the ice is mobile with open water and shear fractures showing by late March.East of this line the ice cover is more stable but break-up is generally complete by June.

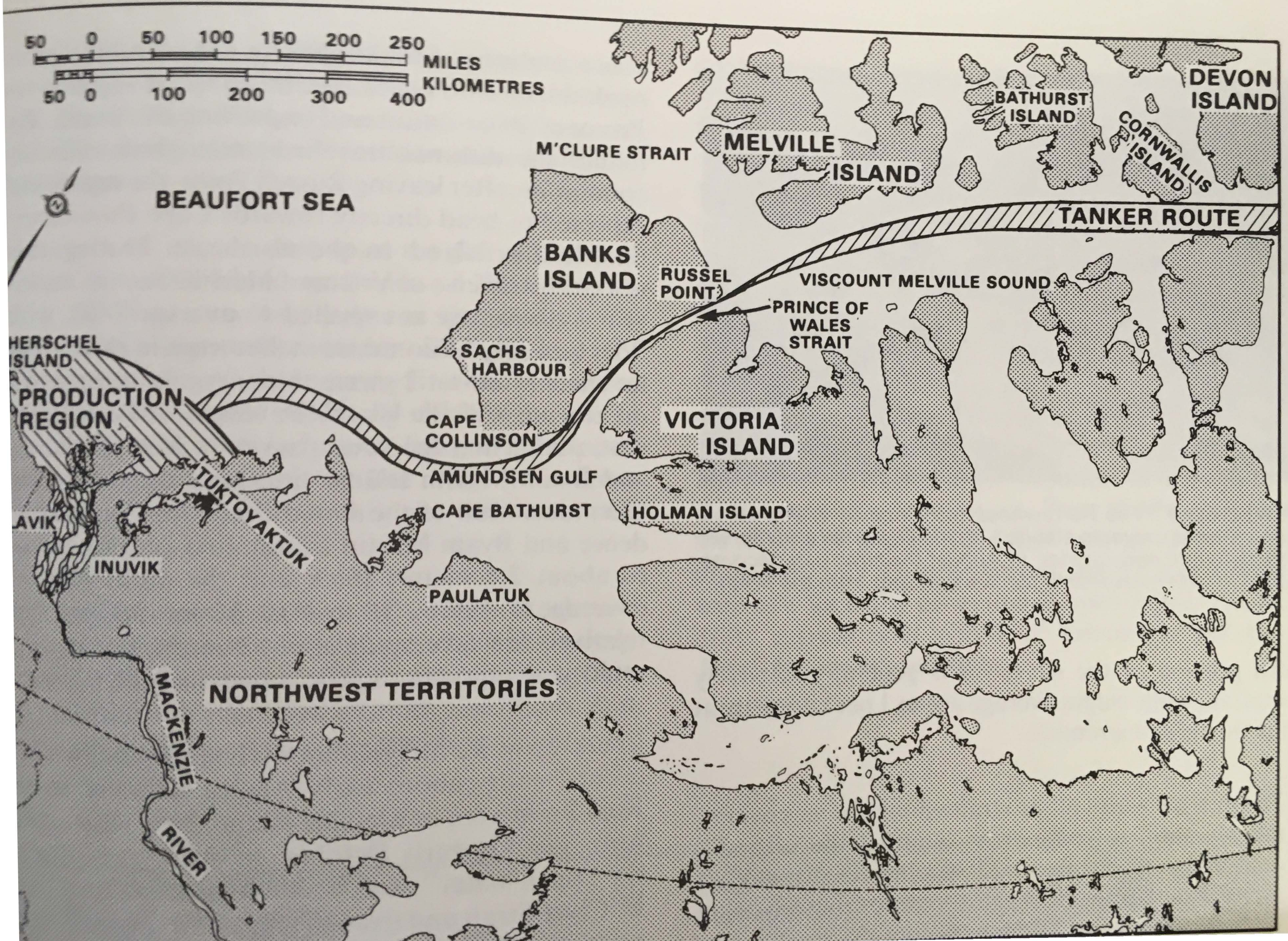
Freeze-up commences in the north and is complete by about mid-November; normal maximum first-year ice growth will be about 1.8 metres.

Water depths in this area all exceed 50 metres and no navigation hazards are known to exist.

6.3.3.3 Prince of Wales Strait

Cape Collinson to Russell Point (about 255 km)

In this portion of the corridor conditions vary, with the percent coverage of multi-year ice increasing from less than 1/10 in the southern portions, to about 4/10 north of the Princess Royal Islands. Thus, the south-



50 0 50 100 150 200 250
MILES
50 0 100 200 300 400
KILOMETRES
BEAUFORT SEA
M'CLURE STRAIT
MELVILLE ISLAND
BATHURST ISLAND
CORNWALLIS ISLAND
DEVON ISLAND
TANKER ROUTE
BANKS ISLAND
RUSSEL POINT
VISCOUNT MELVILLE SOUND
PRINCE OF WALES STRAIT
HERSCHEL ISLAND
PRODUCTION REGION
SACHS HARBOUR
CAPE COLLINSON
VICTORIA ISLAND
AMUNDSEN GULF
TUKTOYAKTUK
CAPE BATHURST
HOLMAN ISLAND
AVIK
INUVIK
PAULATUK
NORTHWEST TERRITORIES
MACKENZIE
RIVER

PLATE 6.3-8 *The narrowness of Prince of Wales Strait allows the ice cover to stabilize rapidly in the fall and remain landfast until midsummer. In August the strait can become clogged with midsummer ice floes drifting from the north.*

ern portion of the ice cover is generally relatively smooth, while ridges average about 1 per kilometre at the northern extremity.

The narrow width of the strait allows the ice cover to rapidly stabilize from north to south in the fall and it remains landfast stable until mid July when break-up starts in the south. By August, old ice from Viscount Melville Sound and M'Clure Strait moves south and can temporarily clog the strait with ice floes. Thus, the northern portion of Prince of Wales Strait usually has significant ice cover throughout the year.

Due to rapid stabilization of ice in the fall and late break-up, the maximum first-year ice thickness can reach 2.1 metres, or about 30 centimetres more than typical Beaufort Sea first-year ice conditions.

At its narrowest point, at 73°N, the strait is about 13 kilometres wide, with about 8 kilometres width between the 55 metre depth contours. At the northern entrance to the strait the depth of water available to the ship is reduced to about 45 metres over a width of about 4 kilometres. A short range position finding system, or a series of permanent radar and visual "sights" would thus be required for navigation in this area. Similarly the vessels must pass to the east of, and within about 3 kilometres of, the Princess Royal Islands. Permanent marks will be also fitted in this area to aid navigation.

6.3.4.4 Viscount Melville Sound and Western Barrow Strait

Russell Point to Lowther Island (about 600 km)

In the Viscount Melville Sound portion of the corridor, ships will consistently encounter the highest concentrations of multi-year ice cover and the least open water, with conditions being worst adjacent to Prince of Wales Strait and improving eastwards. To reduce the distance travelled under these difficult conditions, after leaving Russell Point, the vessels are expected to head directly towards Cape Providence on Melville Island to the northeast. During this northerly traverse of Viscount Melville Sound, multi-year ice coverage is expected to average 7/10, with floes typically 5 kilometres in diameter, in a first-year ice sheet of about 2 metre thickness. In most years, on nearing Melville Island the vessels will veer to the east, paralleling the south coasts of Melville Island and Byam Martin Island, thus keeping to the northernmost limit of the sound. Between Cape Providence and Byam Martin Island, first-year ice grows to about 2.1 metres thick and the multi-year ice coverage is about 2/10 to 4/10. Major ridges will be relatively few, averaging about 1 per 5 kilometres. A multi-year pressure ridge is shown in Plate 6.3-9.

Break-up of ice in Viscount Melville Sound, when it occurs, starts about early August adjacent to the Ross Point area of Melville Island. New ice starts to form again in early October. In most years, during the "open water" season, multi-year ice floes from M'Clure Strait and from the northern channels tend, under the prevailing winds and surface currents, to move to the southern half of Parry Channel where they are then captured within the new ice of early winter. This usually results in a "strip" with less multi-year ice on the northern side of the Channel.

Water depths in this route segment exceed 50 metres and no hydrographic hazards exist. A few radar targets may, however, be required on the south shore of Melville Island.

Presently there is no year-round traffic in this area, shipping being restricted to summer operations. However, after about 1987 two LNG vessels of the

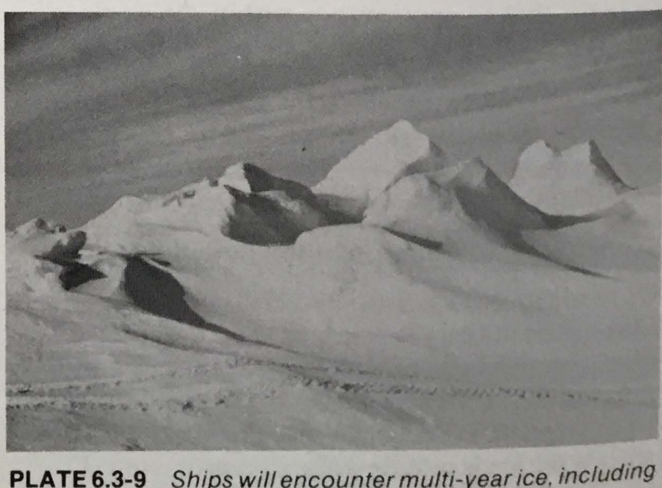


PLATE 6.3-9 *Ships will encounter multi-year ice, including pressure ridges in Viscount Melville Sound.*

Arctic Pilot Project (APP) may be operating eastwards from Bridport Inlet on the south side of Melville Island. High-Fix local position finding systems and other navigation marks could be shared with the APP ships.

The chain of islands that span the Parry Channel from Cornwallis Island to Prince of Wales Island mark the boundary line between the western ice cover, with a high concentration of multi-year ice, and the dynamic, predominantly first-year ice cover to the east. The islands effectively stabilize the winter ice sheet, leading to an early consolidation in October and a delayed break-up in late July. Maximum thickness of first-year ice in this area will be about 2 metres.

The vessels have a variety of routes to choose between these islands with all the passages being deep and wide. The master's decision regarding his route will take into consideration local ice conditions, and the possibility of hunters from Resolute.

6.3.3.5 Barrow Strait and Lancaster Sound

Lowther Island to Cape Sherard (about 520 km).

The eastern sector of the primary shipping corridor for transport of hydrocarbons from the Beaufort Sea - Mackenzie Delta Region is shown in Figure 6.3-9. In winter, in Parry Channel, east of Lowther Island, the vessels will pass from the relatively static ice sheet of Viscount Melville Sound to the dynamic first-year ice of Lancaster Sound. Wide fluctuations can occur in the eastern boundary of the landfast ice. For example, between 1964 and 1979 there was a 400 kilometre difference in the location of the eastern boundary of the landfast ice. West of Maxwell Bay the ice sheet is generally landfast from late November until early July. During this time the ice is in motion with new ice being generated in open water. The ice drifts eastwards at about 12 kilometres per day driven by winds and currents.

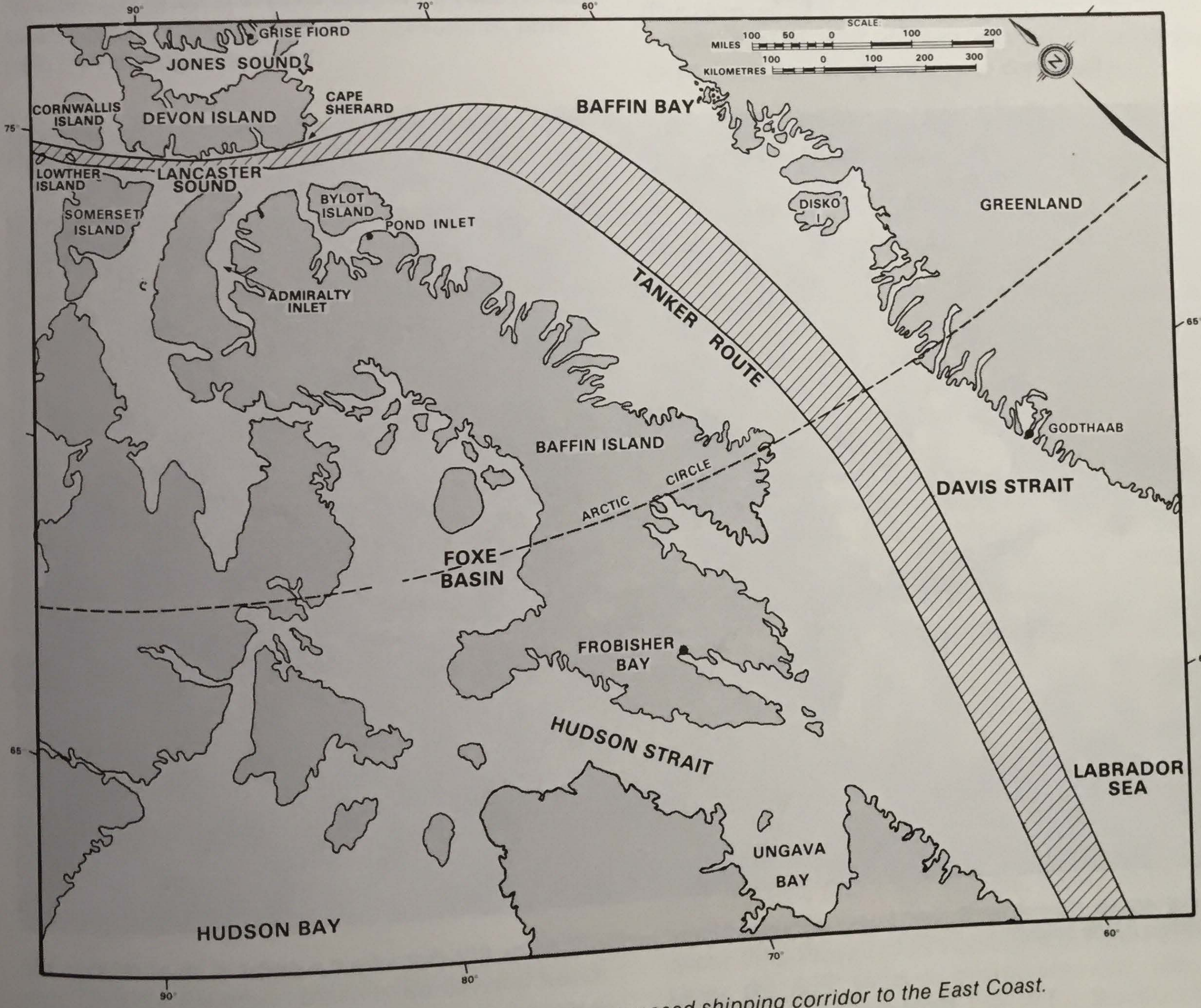


FIGURE 6.3-9 *This map shows the eastern sector of the proposed shipping corridor to the East Coast.*

Multi-year ice concentrations on the northern side of Lancaster Sound are usually low, averaging about 1/10 coverage, however, the southerly portion may have a coverage of 6/10 multi-year. First-year ridges increase in number eastwards, reaching 5 per kilometre, reflecting the higher mobility of the ice cover to the east. Icebergs enter Lancaster Sound from Baffin Bay, but very few travel as far west as 86°W.

Break-up in Barrow Strait normally commences about May with major north-south cracks, but ice coverage does not usually fall below 5/10 until July.

Water depths along this portion of Parry Channel exceed 100 metres and no hydrographic hazards exist. The south shore of Devon Island consists of rocky cliffs and presents an excellent radar image.

There is, at present, no year-round traffic in this area, with vessel movements being restricted to the open water period.In future, in addition to the tanker traffic discussed earlier, LNG carriers and summer supply, there will be ore ships operating from the Nanisivik mine entering Lancaster Sound (Plate 6.3-10) from Admiralty Inlet and summer traffic to the Polaris mine on Little Cornwallis Island.

6.3.3.6 Baffin Bay

Cape Sherard to 70°N (about 830 km).

The tankers will generally operate along a central route close to the agreed median line between Canada and Greenland.

In Baffin Bay, ice conditions vary enormously with regard to thickness, movements, and iceberg densities. Between November and May, central Baffin Bay is covered with predominantly first-year ice up to 1.3 metres in thickness. Because of the constant counterclockwise motion of ice driven by the north flowing West Greenland current and the south flowing Canadian current, leads will open and close. New ice grows then is deformed under pressure. Rafting and rubble formation is extensive. Multi-year ice coverage is inconsistent, ranging from a trace up to 4/10 coverage in some local areas.

Break-up in central Baffin Bay usually starts with the southward extension of the North Water (an area of open water) from northern Baffin Bay, coupled with the northward extension of the Greenland Coast lead. By July an almost ice-free channel is available

PLATE 6.3-10 *Lancaster Sound forms the easternmost sector of Parry Channel which provides a route through the Canadian Arctic Islands.*

through to Lancaster Sound, while the central portion of the Baffin pack is still at 8/10 coverage. Complete clearing usually occurs by mid May.

Freeze-up of Baffin Bay is slow and there are great annual variations. However, it generally progresses from northwest to southeast, with stable ice appearing between early October and mid-November.

Icebergs and bergy bits are common in Baffin Bay (Plate 6.3-11) with the highest densities occurring on the periphery. They move around the bay, as does the sea ice, with the counter-clockwise motion of the currents, taking about three years to complete the circle. Iceberg density is lowest in central Baffin Bay, being less than one berg per 16 square kilometres (Figure 6.3-10). The tankers will travel through this area. Extra care, however, will be taken in this area throughout the year to minimize possible damage to a ship which may occur while proceeding in waters infested by growlers and bergy bits.

The weather in Baffin Bay is very erratic with periods of high winds and low visibility due to fog. These factors, added to the variability of the ice cover, make prudence necessary in ship operations, principally by limiting ship speed.

There are no hydrographic hazards in this central route.

PLATE 6.3-11 *Icebergs and bergy bits are common in Baffin Bay.*

6.3.3.7 Davis Strait and Labrador Sea

70°N to 60°N (about 1,100 km).

This segment of the route represents the transition zone between the predominately ice covered waters of Baffin Bay (150 days open water) and the essentially year-round open water south of 60°N.

The winter ice conditions are poorly consolidated pack ice with a maximum first-year growth of about 0.7 to 1 metre in thickness. This pack is very dynamic with many leads and variations in thickness. Since individual floes tend to be less than 100 metres in diameter, they respond quickly to wind and currents, with movements recorded of up to 90 kilometres per day.

Generally, at 70°N the ships would transit ice cover of between 5/10 and 8/10 concentration from mid-November to July. At 65°N this coverage would last for less than 5 months, and at 60°N the open water season would be about 45 weeks.

In this area water depths along the ship route are considerable and no hydrographic hazards exist. By keeping close to the median line the vessels will be far removed from any drilling operations on the Baffin Island or Labrador coasts.

6.3.4 OTHER ARCTIC TANKERS

6.3.4.1 LNG Tankers and Methanol Tankers

The carriage of liquid natural gas (LNG) by sea is a safe, proven, and efficient method of delivering large quantities of this energy to consumers.

In the Beaufort Sea Region, natural gas will be produced from non-associated gas fields and through crude oil production. Although the proponents believe that gas from the Beaufort Sea-Mackenzie Delta Region would most likely be transported to market in a gas pipeline, it may be possible to ship this as LNG on a year-round basis along the same route as described previously for the surface oil tankers. The gas would be liquefied by cooling to -165°C, and stored in insulated tanks at atmospheric pressure before it is shipped.

Liquid natural gas is a cryogenic liquid (-162°C) and contains a large amount of energy per unit of volume. Thus, the systems that transfer and store the liquid must be of the highest quality, design, and construction. Piping and other portions of the structure in direct contact with this liquid are generally of stainless steel or aluminum.

LNG, composed principally of liquid methane, is not considered a pollutant since any gas leaked or spilled vapourizes very quickly even in the coldest environment, and disperses upwards into the air leaving no residue behind.

It is expected that LNG tankers, if ever employed, would be similar to those already proposed for the Arctic Pilot Project (APP) as shown in Figure 6.3-11. Using the APP ships as prototypes, and with an increase in Ice Class from 7 to 10 for Beaufort Sea

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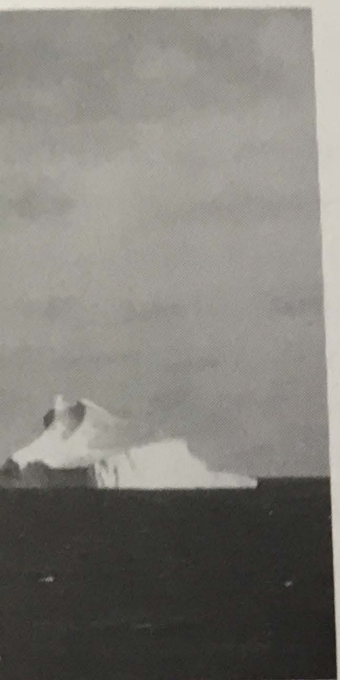

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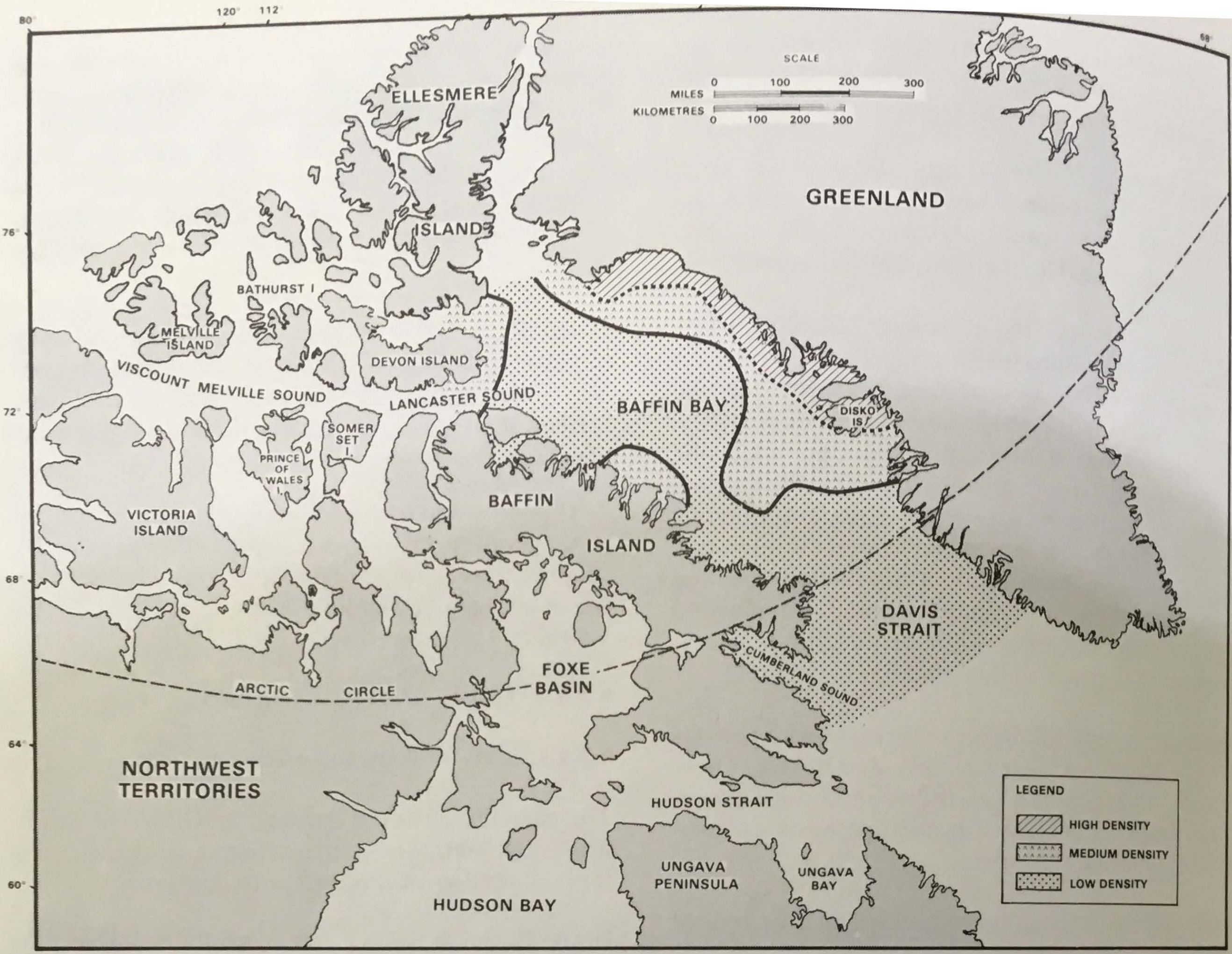

FIGURE 6.3-10 *This map shows iceberg density in Baffin Bay. Arctic tankers will sail down the centre of the bay where the iceberg density is the lowest.*

service, the vessels would have the following approximate characteristics:

length	360 m
beam	50 m
draft	15 m
cargo capacity	140,000 m^3
power	105 MW

These vessels would have a conventional LNG containment system and a propulsion plant fired by gas turbines.

Based on the existing excellent world-wide safety record of LNG ships over the last twenty-five years, the proponents believe that, with proper care in design and prudent operation, this record can be continued in the Arctic. Similar operational practices and equipment as described previously for the oil tankers will be applied. In addition there would be cargo sensing equipment for cryogenic temperatures and for flammable vapours.

Methanol is a liquid which may be produced from natural gas. It is used as a gasoline extender, as a clean burning fuel source or as a feed stock for a wide variety of industries. Methanol has no unusual temperature requirements for its transport by tanker ships and requires only that it be kept from mixing with ballast water. As it is corrosive and destructive to certain materials, principally plastics and some coatings, modifications to existing tanker designs would be required.

While no specific details of a methanol tanker have been developed, the vessel would be essentially similar to crude oil tankers. The probable characteristics are:

length	400 m
beam	53 m
depth	39 m
cargo deadweight	203,000 tonnes
power	120 MW

Although at present there are no plans for transporting methanol by tanker from the Beaufort Region, if they were eventually used, they would operate along the same route as the oil tankers, using essentially the same operational procedures and equipment.

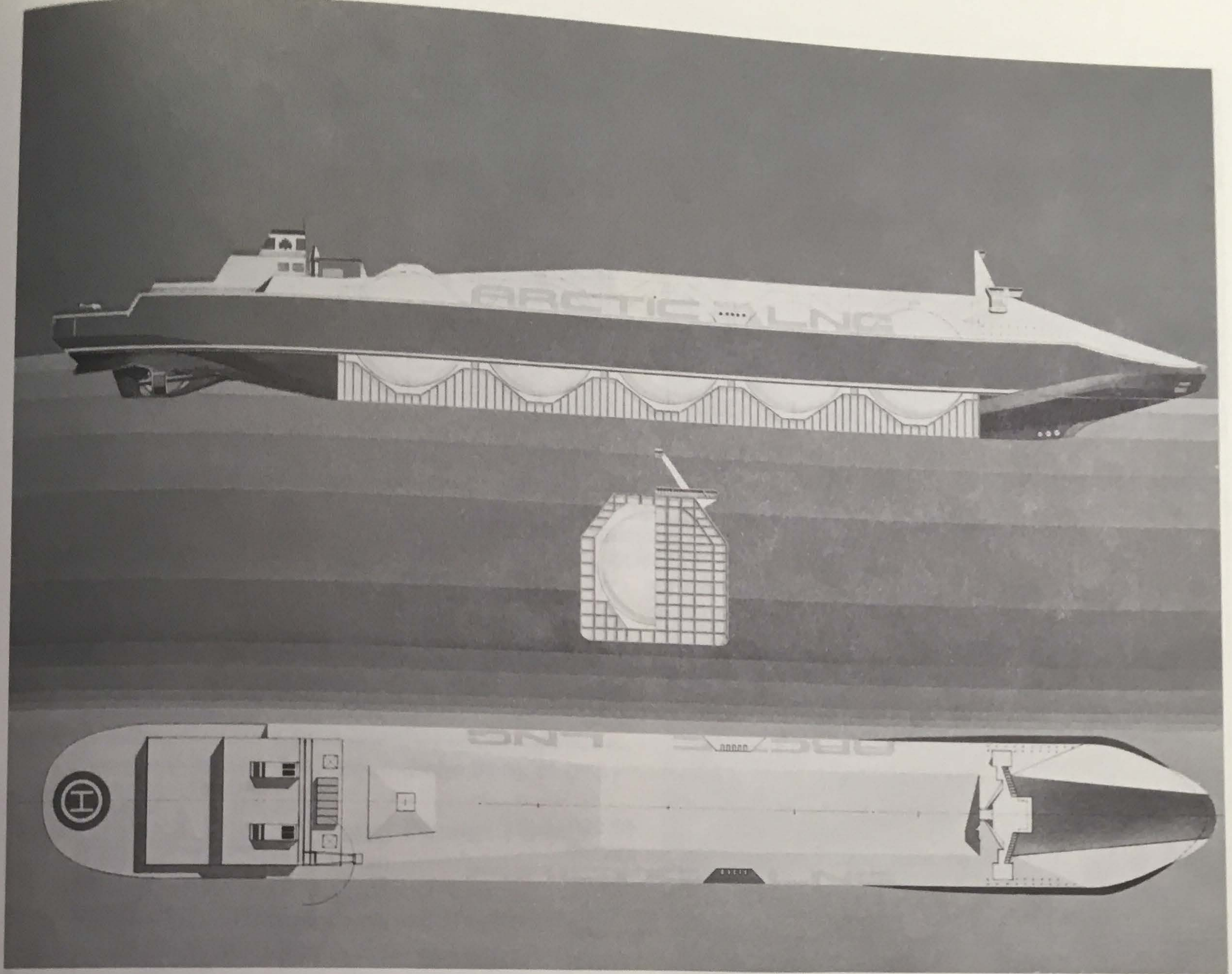

FIGURE 6.3-11 *An alternative to pipelines for the transport of gas from the Beaufort Sea-Mackenzie Delta would be to liquefy it and ship it through the Northwest Passage by tanker. Tankers would probably be similar to those proposed for the Arctic Pilot Project illustrated here.*

6.3.4.2 Submarine Tankers

There are proposals to use submarine tankers to transport hydrocarbons to southern markets. Submarines would operate beneath the ice and thus not require the special icebreaking features of Arctic tankers. Since the late 1950's commercial submarine tanker systems have been investigated by some engineering firms.

A submarine oil tanker conceptual design has been developed and hydrodynamically verified by model tests. The dimensions of such a vessel, as proposed by General Dynamics and Transpolar Shipping, would be a length of 310 metres, a beam of 52 metres and a cargo carrying capacity of 185,000 tonnes.

Submarines have also been suggested as a potential carrier of liquefied natural gas (LNG) from the Beaufort Sea to southern Canadian markets. Preliminary studies (Veliotis, 1981) have provided a conceptual design for such a vessel, which is likely to be 450 metres in length, with a beam of 70 metres and a cargo carrying capacity of 140,000 cubic metres. The conceptual General Dynamics submarine LNG tanker is illustrated in Figure 6.3-12.

Although the submarine LNG tanker is much larger than the conceptual submarine oil tanker, the features are similar. Major differences are in the ballast and cargo systems. Because the cargo tanks cannot be ballasted with sea water, there would be a large variable ballast tank in the centre of the hull containing sufficient additional seawater to submerge the submarine when the cargo tanks are empty.

If methanol were produced in the Region, submarine methanol tankers might also be used to transport this product. Although no detailed design has been prepared, the general characteristics and operation would be similar to the submarine oil tanker.

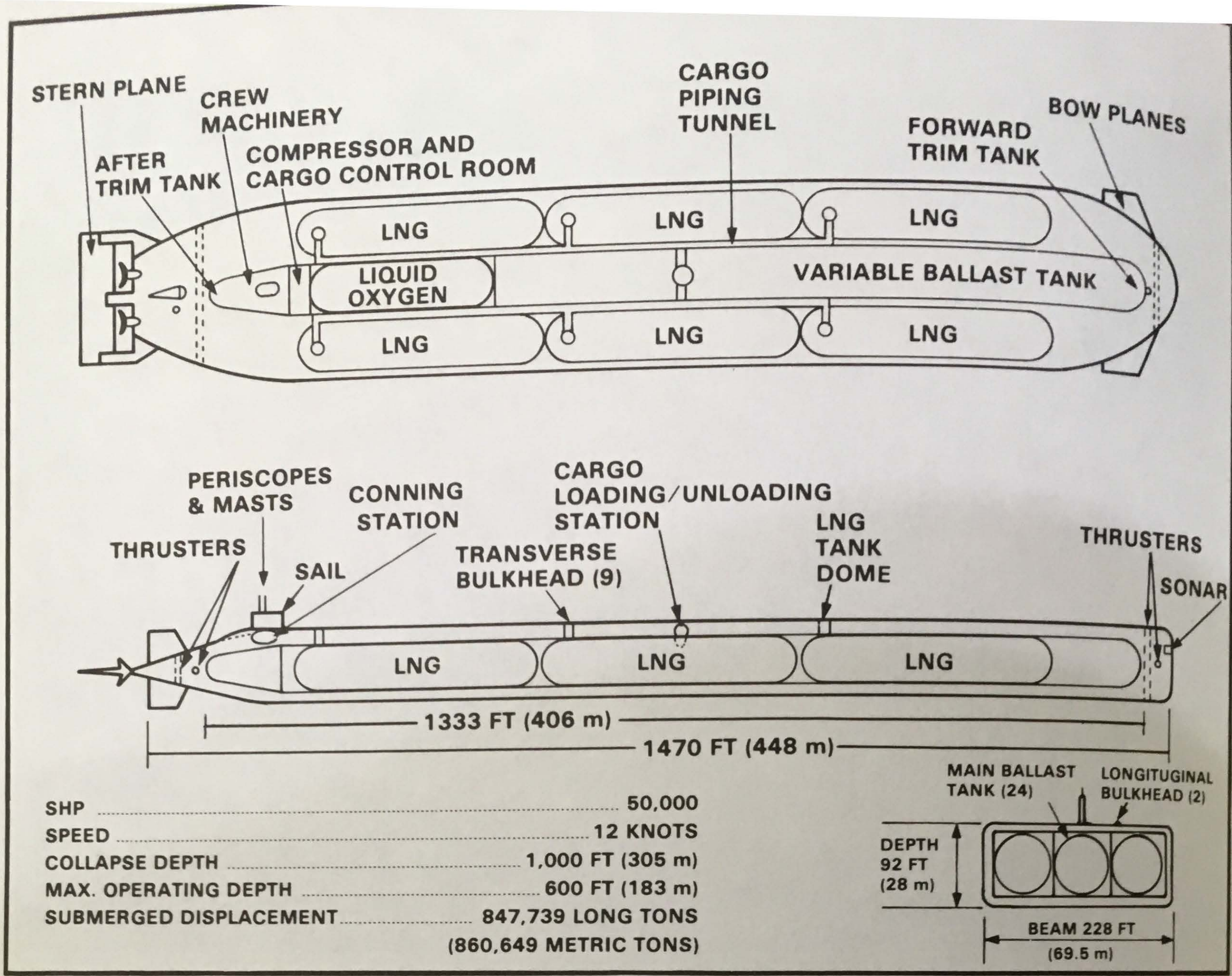

FIGURE 6.3-12 *Submarines have been suggested as potential carriers of hydrocarbons from the Beaufort Sea to southern markets. The General Dynamic's concept of an LNG tanker design is shown here (Veliotis and Reitz, 1981)*

Due to the need for deep water, only two routes are possible for the proposed submarine tankers. The projected routes from the Beaufort Sea would proceed almost due north, passing through deep water beyond the continental shelf to the west of the Arctic Islands. At this point the submarine tanker may either follow a route between Ellesmere Island and Greenland or continue due north of Greenland, swing south between Greenland and Spitsbergen and on into the Atlantic Ocean to the east coast terminal. This longer route, about 16,500 kilometres, has water depths always in excess of 500 metres. At an average speed of 7 metres per second a round trip is estimated to take about 30 days, allowing about 11 trips per year.

Submarine tankers are not likely to be used for hydrocarbon transportation from the Beaufort Sea-Mackenzie Delta Region for many years, due to technological, cost and draft considerations.

6.3.5 POTENTIAL ENVIRONMENTAL DISTURBANCES

Year-round passage of Arctic icebreaking tankers will cause a certain amount of environmental disturbance. These potential disturbances are briefly described here and examined in detail in Volume 4. The major disturbances are the physical effects of the vessel on ice (Plate 6.3-12), particularly landfast ice, and the potential effects of sound generated by the vessels' passage. The ships will also discharge ballast water and a small amount of treated sewage.

The probability of a tanker oil spill (See Volume 6) is considered low due to the unique design and operational features of the prospective tankers. The cargo will be carried only in centre tanks remote from the side and bottom plating. The fuel for the main and auxiliary engines will be carried in similarly isolated tanks.

The passage of icebreaking tankers through the Arctic will inevitably cause some (mostly local) distur-

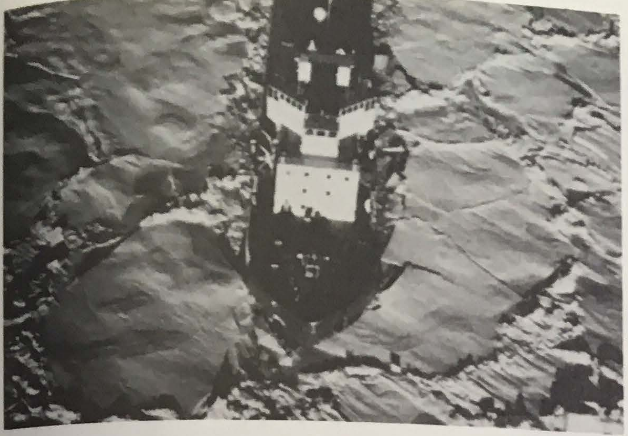

PLATE 6.3-12 *The passage of icebreaking tankers through the Arctic year-round will cause some disturbance of the ice sheets. The KIGORIAK icebreaker is shown here traversing the ice-covered Beaufort Sea.*

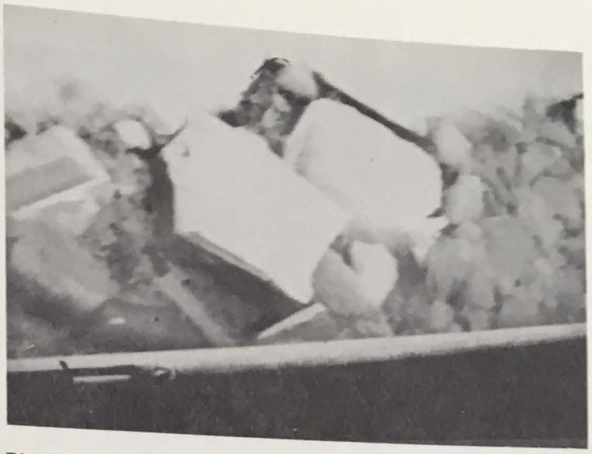

PLATE 6.3-13 *When a ship passes through an ice sheet, the ice is broken and forced down under the vessel. Some of this is broken again by the propellers and floats to the surface behind the ship as illustrated.*

bance to wildlife. Sea-birds and mammals such as seals, polar bears and whales in the immediate vicinity of the ships may be disturbed. Since seals are widespread throughout the ice cover of Parry Channel and Baffin Bay, it is possible that some, particularly pups, will be killed or injured by the ships.

6.3.5.1 Physical Effects of Vessel Passage Through Ice

When a ship passes through an ice sheet the ice is broken and forced down under the vessel in relatively large pieces. Some of the ice then passes through the propellers where it is broken again into much smaller pieces. This mixture of ice pieces floats to the surface behind the vessel (Plate 6.3-13). The final appearance of the ship's track, is thus not usually an open channel but a strip of rubble-like ice pieces varying from slush to pieces 4 or 5 metres in diameter. At temperatures below freezing, these freeze together quite rapidly by supercooling of the water between them. Only in very thin ice when the ship is sailing relatively fast would there be appreciable open water on the surface (Plate 6.3-14). In the winter, this surface water rapidly looses heat to the atmosphere and new ice forms, "healing" the ice sheet.

PLATE 6.3-14 *Only when a ship is sailing relatively fast through thin ice is a track of open water left behind the vessel.*

There is a concern that repeated vessel passages may cause significant changes in the ice sheet. For example, as the tankers pass through regions of landfast ice, the repeated exposure of water in their wake to rapid refreezing will augment ice growth. As the ice is thickened by repeated passages, it may be necessary to break a new path nearby. The result, near the end of winter, will be localized thickened strips of ice.

In Lancaster Sound, landfast ice exists to the west and moving ice to the east, the transition being marked by a landfast ice edge from early January to mid-June. It is possible that icebreaking tanker traffic transitting Lancaster Sound could inhibit stabilization of a fast ice edge and thus result in larger than average areas of moving ice in late winter and spring. The possibility of this occurring and resulting effects are discussed in Volume 4.

Localized instability of the ice sheet due to tanker traffic may also alter the existing pattern of thermal

cracks and leads within the ice sheet. These cracks and leads occur regularly in the ice sheet at predictable locations and are hunted intensively by the Inuit.

Also, the ship's track may impede travel across the ice by caribou or Inuit hunters. This may happen if the ice in the track does not reconsolidate quickly or if repeated passages cause such a build-up of ice blocks as to make travel over them difficult or impossible. Tests in the Beaufort Sea in late November, illustrated in Plates 6.3-15 and 16, showed, however, that slush in a ship's track froze to 2.5 centimetres thick within an hour, enough to support a man's weight; and that after 2 hours it was 5 centimetres thick, enough to support a skidoo. Further work carried out in March and even June, 1982, showed that the ship track consolidated quickly under all conditions, allowing skidoos towing Komatiks to cross within a few hours at most. Presently, Inuit travel extensively on the fast ice sheet during the spring in order to extend their hunting season.

In the open water of summer, the ship's wake may travel for some considerable distance. In newly forming landfast ice in the fall, waves generated by the ship could break ice over several ship widths. For example, a ship travelling through ice 30 centimetres thick is likely to break ice over about 4 ship widths, thus disrupting ice in a 200 metre wide swath. In thicker ice, however, ship-generated waves will not travel so far and thus, in 60 centimetre ice for example, the disrupted zone is likely to be only about 100 metres wide. In winter, the greater thickness of ice cover will make it necessary for the ships to travel at lower speeds and so the wake will not travel so far. There will thus be less deformation or failure of ice in winter, the ship only leaving a broken track.

Changes in the ice configuration brought about by ships passages may affect marine mammals. For example, concern has been expressed that whales may, due to migratory and breeding pressure, follow the ship into the intact ice sheet using the ship's track as an artificial lead and may then subsequently be trapped if the track freezes over. These concerns are discussed in Volume 4. Plate 6.3-17 shows whales in a natural lead in ice covered waters.

It must be emphasized that ice conditions in the Arctic are variable from year to year, dependent on

PLATE 6.3-15 *In cold temperatures, blocks of ice in a ship's track freeze together quite rapidly. The icebreaker KIGORIAK and supply ships have been used for an experimental track research program in the Beaufort Sea to test the time required for a ship's track to freeze over. Hunters were able to cross the ship tracks on foot in less than an hour after the ships passed and within a few hours with skidoos and komatiks.*

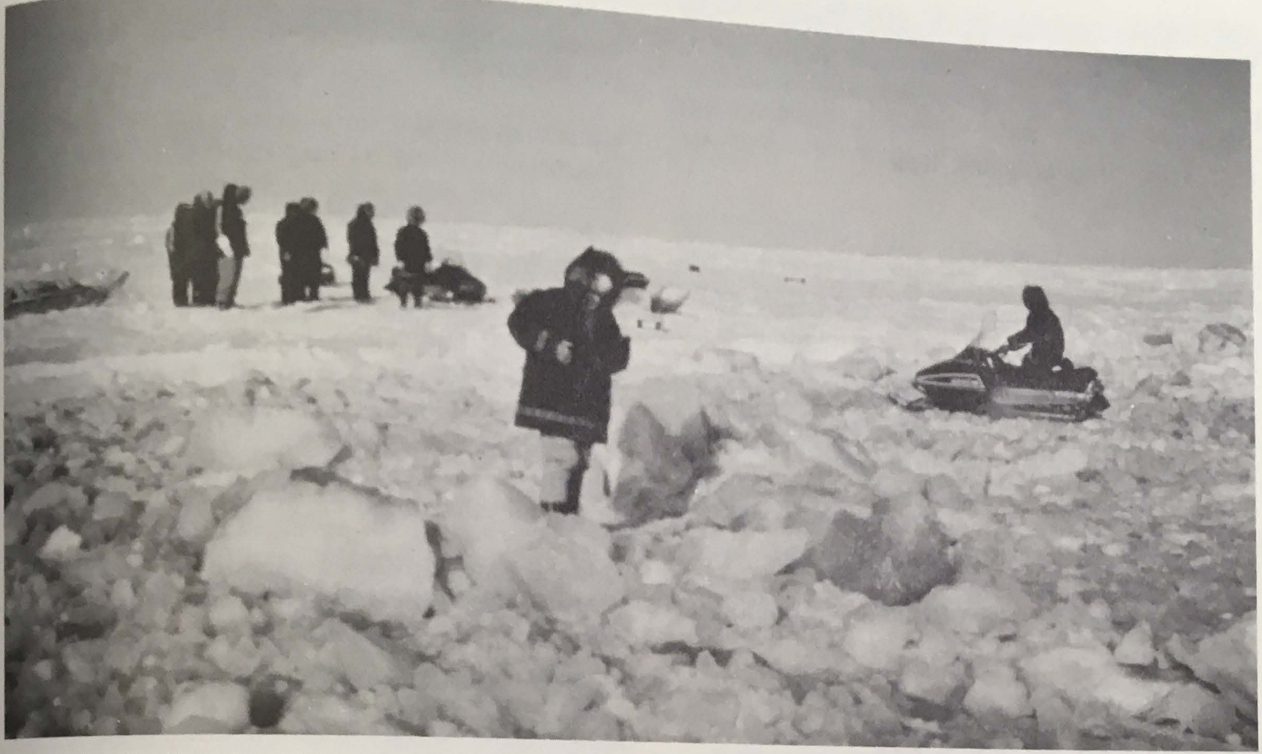

PLATE 6.3-16 *Experienced hunters of the Arctic and research scientists worked together during the icebreaker track research program.*

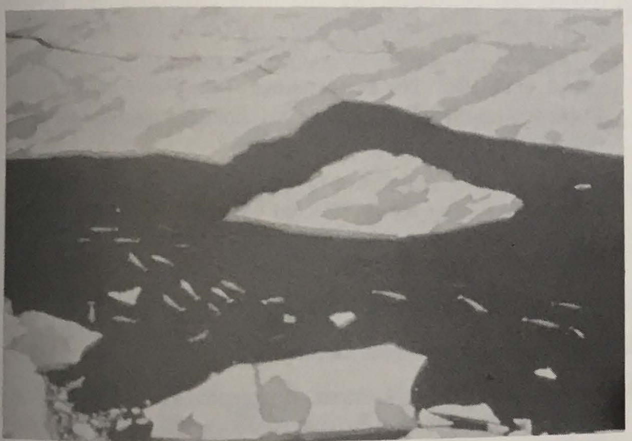

PLATE 6.3-17 *This photograph shows a pod of whales in Arctic waters.*

weather conditions, and that in some areas, for example Lancaster Sound, the ice cover is very mobile. Thus, in most cases, the extent to which icebreaking tankers may alter existing conditions may not be significant compared to the natural range of variation.

The passage of tankers through ice would also generate local ice fog. The phenomenon of ice fog occurs when a cold air mass overlies a body of open water. As the water surface is cooled, water evaporates into the air. These water droplets quickly crystalize in the cold air mass, and, if the air is still, they can be held in suspension in the immediate vicinity of the open water. However, even a very thin layer of surface ice prevents ice fog formation. Generally, any open water in a ship's track will freeze over very quickly, hence, minimizing ice fog generation.

6.3.5.2 Effects of Ship Noise

The underwater sound intensity generated by a ship is not a function of the vessel tonnage or size, but rather of the propeller blade loading, which causes blade cavitation, and of ship speed. Propellers not operating efficiently also tend to be noisy. About 80% to 85 % of the noise radiated, will come directly from the propellers. This radiated energy will cover the frequency spectrum from as low as a few hertz (Hz) to as high as 100 kilohertz (kHz). However, most of the acoustic power will be concentrated below 100 Hz. Noise will also be generated by the impact of the ship on the ice and fracturing of that ice. This underwater noise generated by the icebreaking tankers could affect marine life along the route.

Airborne noises generated by the tankers will include those created by the exhaust funnel, ship machinery, icebreaking and turbulence. These noises, however,

will rapidly attenuate in air and be a localized phenomenon.

6.3.5.3 Discharge of Ballast Water

When the icebreaking tanker leaves its southern terminal it will be empty of oil and, consequently, must take onboard salt water ballast into the wing tanks. IMCO standards require that as a minimum, the propellers must be completely submerged when leaving port on ballast. The volume of ballast taken on board at the southern terminal will be minimized and adjusted to maximize cruising efficiency and vessel manoeuvring during open water travel. Upon reaching the ice edge in the Northwest Passage, more ballast water will be taken on to reach the optimum icebreaking draft. This increase in mass improves the ship's performance in heavy ice ridges and thick multi-year floes.

Large fish will be prevented from entering the ballast tanks by a series of strainers and valves. The largest organism that could pass would be about 2 centimetres in diameter.

Upon arrival at the northern terminal the vessel will commence loading oil cargo into the centre cargo tanks, at the same time discharging the salt water ballast. The rate of discharge will be the same as the oil loading rate, that is about 17,000 tonnes per hour. This means that the vessel's draft will remain constant over the liquid transfer time. The water being discharged will remain constant over the liquid transfer time. The water being discharged will be clean since it comes from segregated ballast tanks. However, it has been suggested that the introduction of this "foreign" salt water to the vicinity of the northern terminal may have some effect upon the local northern biota.

Cooling water, treated sewage and bilge water and deck washings will be discharged along the ship route in accordance with applicable regulations.

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CHAPTER 7
CANADIAN BENEFITS

7.1 INTRODUCTION

7.1.1 OVERVIEW

The development of the Beaufort Sea-Mackenzie Delta hydrocarbon resources can make a major contribution to the future well-being of Canada. With a technically achievable production potential of over one million barrels of oil per day by the year 2000, and expenditures of approximately $100 billion (1981 dollars), this development would infuse substantial wealth into the Canadian economy. It would create jobs and income for workers in all Provinces and Territories, and provide significant growth in the northern regions. Beaufort oil production could assist in making Canada self-sufficient in crude oil supply, and could turn government deficits into surpluses.

The assessment of economic and industrial benefits is based on the same scenarios as used for the environmental and social impact assessments. In accordance with the Guidelines issued by the Environmental Assessment and Review Panel, two alternative transportation systems have been considered, one for an entire marine system, and one using a pipeline. To allow an assessment of the variation of the impacts with the levels of oil and gas production, two production levels have been analyzed: a technically achievable rate of development, and an intermediate rate of development. These levels encompass crude oil production profiles illustrated in Figure 7.1-1. Following is a summary of cases reviewed, with ranges representing the two levels of activity.

Marine Mode:

1986 - 1988 startup :

270,000 to 450,000 barrels per day production by 1990 :

200,000 DWT Arctic Class crude oil carriers, traversing year-round the Northwest Passage to Canada's East Coast.

Pipeline Mode :

1987 - 1989 startup :

270,000 - 450,000 barrels per day production by 1990 :

36" or 42" diameter crude oil pipelines built along the Mackenzie Valley Corridor, and connecting at Edmonton to Inter-Provincial Pipeline.

Gas production involving delivery via a pipeline by 1990 to 1992 is also included. Gas pipeline alternatives are: a pipeline through the Mackenzie Valley corridor, the Polar Y-line and, a Dempster connection to the Alaska Highway Pipeline. For the purposes of this impact analysis the last option has been

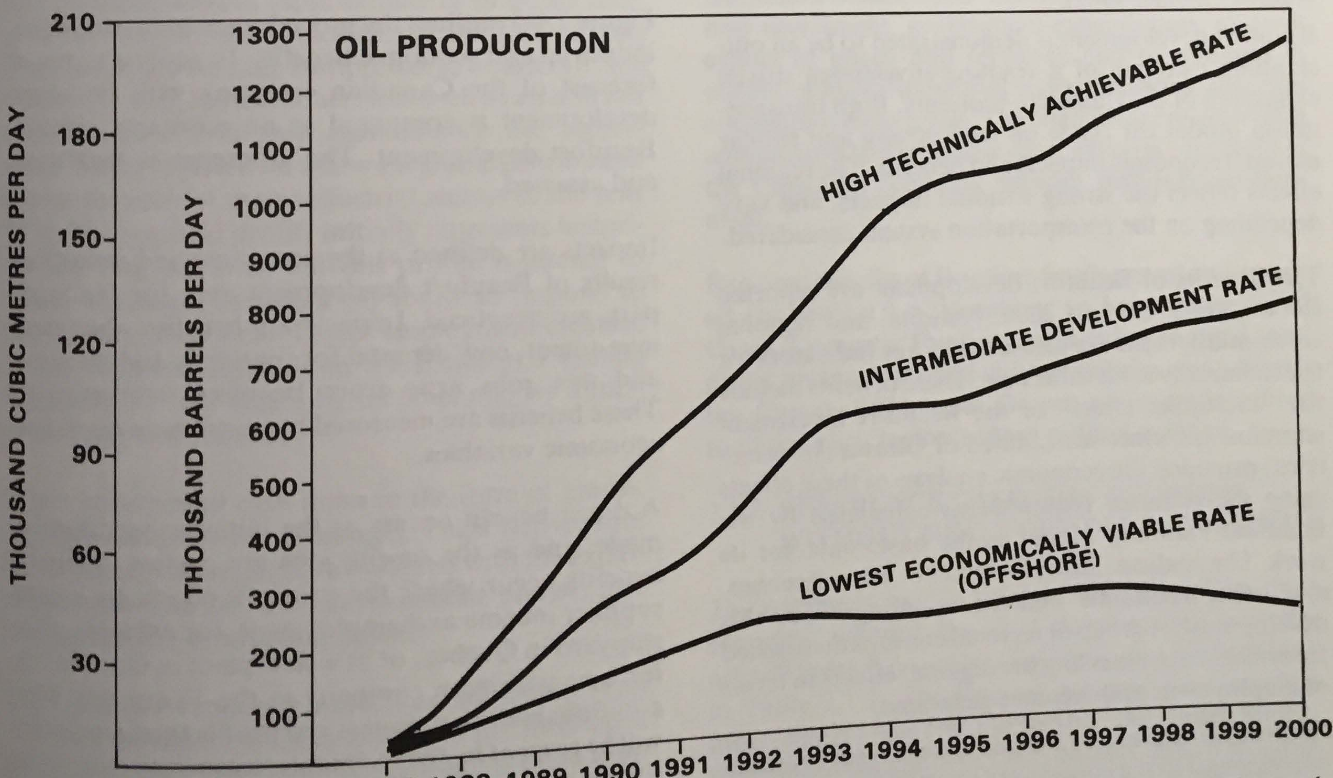


FIGURE 7.1-1 *A range of oil production rates can be achieved depending upon the need for oil and on the effects of numerous other variables which influence development. This chapter examines the economic effects of a technically achievable rate of development, and an intermediate rate of development.*

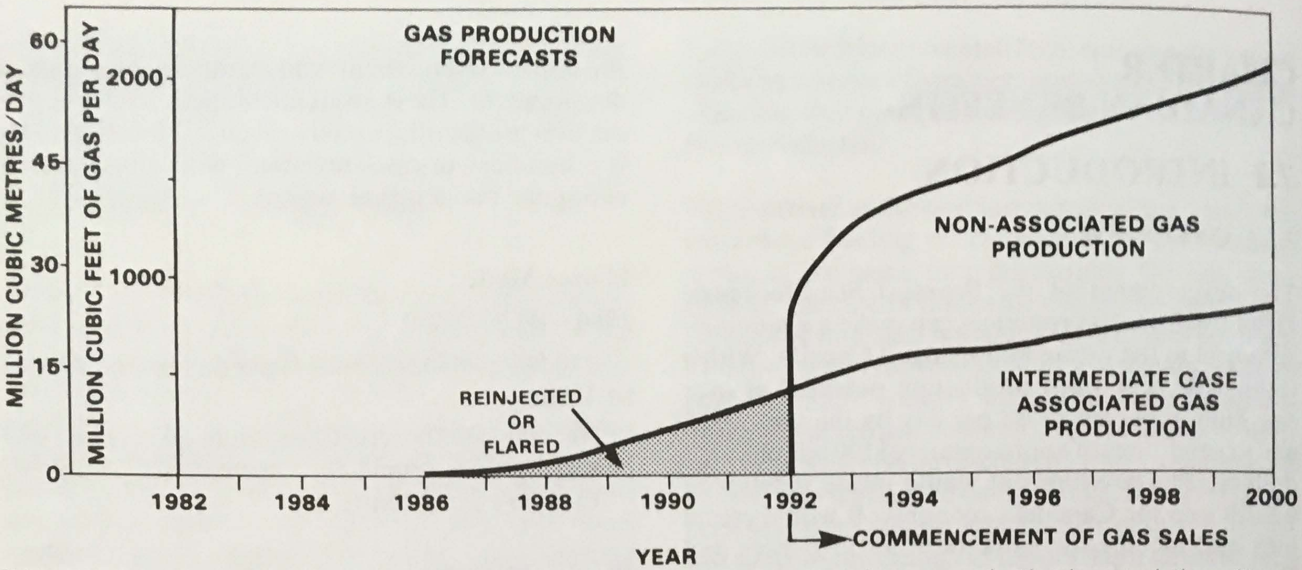


FIGURE 7.1-2 *Gas production forecasts resulting from Beaufort Development, for gas production in association with an intermediate rate of oil production development and for production from new gas reservoirs.*

used. Anticipated gas production levels are shown in Figure 7.1-2.

The development scenarios are simulated with the Beaufort Canadian Benefits Planning Model (Beaufort Planning Model). This model incorporates geological and technical information on Beaufort development activities, and translates these into demand forecasts for personnel, materials, and services. The Beaufort Planning Model further generates a corresponding supply forecast. A description of the Planning Model, computer printouts and other summary tables are provided as a support document to this volume (Dome, 1982).

Beaufort development is demonstrated to be an outstanding example of a resource-investment driven expansion of the Canadian economy. Both transportation modes for crude oil have strong and similar national economic impacts and benefits. The regional effects reflect the strong national impacts, and vary depending on the transportation system considered.

The benefits of Beaufort development are reported for the years 1981 to 2000. National and regional economic benefits are measured by key indicators for the technically achievable case. These benefits include the "multiplier effect" of the Beaufort investment stimulus. Informetrica Limited of Ottawa (Informetrica) provided the economic analysis of these effects using the resource requirements calculated by the Beaufort Planning Model as the basic data for its work. The analysis illustrates incomes, jobs, revenues, and other economic benefits resulting from this development. A group of regional consultants assisted Informetrica in assessing the regional effects in terms of employment and incomes generated.

Programs and plans by the Beaufort project sponsors are reviewed in the context of Government objectives and policies. Industry actions on procurement, hiring of staff, and on the acquisition of services are such that northerners, and indeed all Canadians, will have the opportunity to contribute to, and thus benefit from, this development. Northerners will have the first consideration for jobs and the provision of goods and services to the full extent of their capabilities.

All dollar values reported herein represent 1981 Canadian dollars unless otherwise stated.

7.1.2 TYPES OF BENEFITS AND HOW THEY ARE MEASURED

Figure 7.1-3 outlines the procedure used to determine industrial and economic benefits. In general terms, a forecast of the Canadian economy with Beaufort development is compared to an economy without Beaufort development. The difference is measured and assessed.

Impacts are defined as the economic and industrial results of Beaufort development and, for the most part, are beneficial. Impacts are benefits when new investment, new demand for materials and services, and new jobs arise from Beaufort development. These benefits are measured by improvements in key economic variables.

A direct benefit occurs as the initial expenditure is made, and as the on-site jobs are created. Indirect benefits occur where the project's purchases create supplier income and employment, for example, at a shipyard in Quebec, or at a steel plant in Ontario, or for a construction company in the Territories. The additional salaries, wages, and profits thus generated will be respent by the recipients to generate more jobs for the suppliers of consumer products and services, and so on. These subsequent rounds of spending are the induced effects.

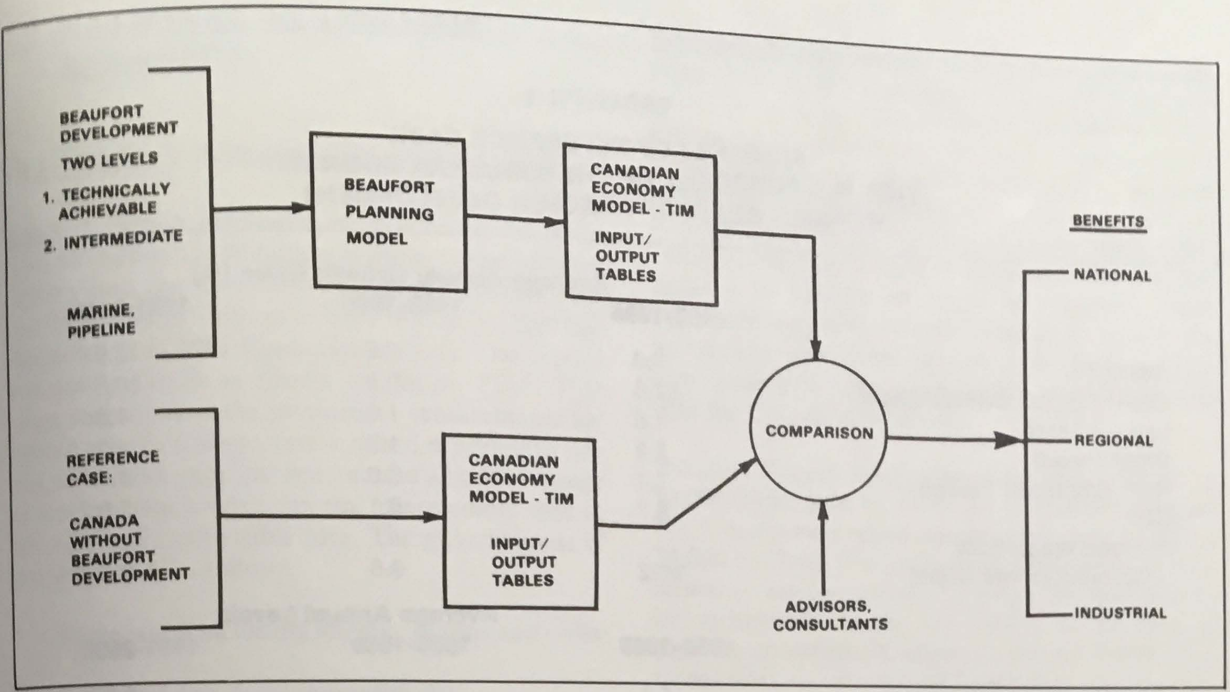


FIGURE 7.1-3 *Outline of method to determine the economic and industrial benefits of Beaufort Region development. Two levels of Beaufort development are considered, a technically achievable rate, and an intermediate rate. The Beaufort planning model translates development activity into investment, and into demand for personnel, materials and services. Informetrica's TIM models the economic effects. A comparison of results to a reference case without Beaufort development illustrates the benefits.*

Direct expenditure benefits from Beaufort Region development are reported annually for the period 1981 to 2000, by 49 industrial and services items and by 11 regions in Canada. Canadian content and regional sourcing are determined by using the Beaufort Planning Model. Approximately 40 of the categories are industrial commodities (materials), ranging from sand, gravel and compressors, to aircraft and trucks. As well, industrial services such as air and rail transportation and ship maintenance are represented. Superimposed on this is a regional distribution profile for each of these industrial sectors to the year 2000. The regional profile initially represents historical sourcing patterns, but this profile is altered to reflect increased Canadian capability to respond to this demand over time. Direct employment creation is also reported annually in the Beaufort Planning Model by 30 skill types, by income, and by anticipated region of residence.

Direct government cash flows in the form of grants, royalties and taxes are measured. These derive from the technical requirements associated with the exploration, construction, and development phases, and revenues in the production phase.

The Canadian economic impacts are measured by an econometric model of Canada called TIM, developed by Informetrica. The model incorporates more than 4,000 variables measuring economic activity, determines production in 23 sectors, and utilizes input-/output tables to link demand and supply. Data on Beaufort development is provided to TIM by the Beaufort Planning Model.

The national effects of Beaufort development are measured by changes in the value of the Gross National Product, (and its components such as business investment, government expenditures, and net export of goods and services), and by changes in output of major industrial sectors, personal incomes and employment levels. The changes are measured in comparison to a reference case, which is a forecast of the Canadian economy without Beaufort development.

Regional benefits of Beaufort development are reported for several key variables, such as the regional Gross Domestic Product, total value shipped, and direct plus indirect and induced employment. Statistics Canada 1974 Input-Output tables were utilized to derive each region's share of final demand.

7.1.3 REFERENCE CASE: THE ECONOMY WITHOUT BEAUFORT DEVELOPMENT

The reference case is a forecast of a strong Canadian economy without Beaufort development over the next 20 years.* A summary of the forecast is provided in Table 7.1-1. The forecast assumes for Canada's most closely allied trading partner, the United States, that output stagnates in 1982, but is followed by three years of robust growth. Steady, moderate growth continues thereafter. The Canadian exchange rate

TABLE 7.1-1

SUMMARY OF REFERENCE CASE. THIS IS A FORECAST OF THE CANADIAN ECONOMY WITHOUT BEAUFORT REGION DEVELOPMENT

	Average Annual Growth Rates (%)		
	1982-1985	1986-1990	1991-2000
Real GNP	3.3	2.2	2.9
GNP (Current Dollars Basis)	12.5	10.8	10.6
Labour Force	1.8	1.5	1.3
Employment	2.2	1.5	1.5
RDP/Employed Person	1.1	0.6	1.4
CPI	8.7	8.1	7.0
Average Wage Rate (Current Dollars Basis)	10.2	9.6	9.3
	Average Annual Levels		
	1982-1985	**1986-1990**	**1991-2000**
Unemployment Rate (%)	7.1	5.8	5.5
Merchandise Trade Balance (Billions of Current $)	10.5	14.8	32.4
Current Account Balance (Billions of Current $)	-7.5	-13.2	-23.2
Government Balance (Billions of Current $)	-1.1	-2.8	2.5
Net Imports of Crude Oil (000 b/d)	440	520	330

Source: Informetrica, 1982

(cents U.S. per Canadian dollar) rises to 85 in 1985, and gains a further cent each year, stabilizing at 90 in 1990. Canadian crude oil demand exceeds supply throughout the forecast period, resulting in continual importing of foreign crude oil. World crude oil prices are assumed to remain constant at $34.00 U.S. per barrel through 1982 and 1983, and rise thereafter in real terms 1.5% to 2.0% per year above the rate of U.S. inflation (as measured by U.S. GNP deflator). For domestic crude oil pricing, the provisions of the National Energy Program as modified by the agreements between Ottawa and the producing provinces in 1981 are assumed to hold. This means that the price of new oil produced in Canada is near the price level of international crude oil delivered to Montreal.

Generally, the reference case presents real economic growth of 1.9% to 3.3% per year for the Canadian economy to the end of this century. Major energy investments, including tar sands developments and the Alaska Highway Natural Gas Pipeline, are concentrated in the late 1980's, creating a stimulus for this moderate growth. Offshore East Coast oil development at Hibernia emerges in the late 1980's and into the 1990's.

As experienced during the second half of the 1970's, there will be strong growth in employment in Canada during the 1980's. The employment level fluctuates between 6% and 7% in the last half of the decade. After 1990 slower labour force growth results in lower unemployment levels of 5% to 6% through the 1990's.

Inflation, as indicated by the rate of change in the Consumer Price Index, is gradually brought down to a 7% annual increase by the 1990's. This is occasioned by improvements in the value of the Canadian dollar, by increased imports, and by a less rapid growth in domestic oil prices than in the past.

The reference case forecasts that current expenditures of Government (all Governments) will decrease as a share of GNP. Further, Government revenues and expenditures will remain nearly in balance until the 1990's. After 1990, it is forecast that Government surpluses will develop.

*Short term economic conditions have changed significantly since the beginning of 1982, the point in time when this economic forecast was prepared. However, the reference case could still be representative of the longer term outlook.

7.2 NATIONAL ECONOMIC BENEFITS

7.2.1 PROJECT INVESTMENT AND REVENUE

Beaufort Region development is forecast to inject from $27 billion to $40 billion in project expenditures directly into the Canadian economy between now and 1990, and $67 billion to $102 billion by 2000 (all expenditures in 1981 Canadian dollars). The capital investment profile is shown in Figure 7.2-1. This range encompasses the investment requirements for either a marine transportation based production system, or a major pipeline system, and also for a range of development levels from the intermediate case to the technically achievable case. The general areas of investment are as follows:

- Exploration including seismic, islands and wells;
- Appraisal and development wells;
- Production islands and production facilities;
- Infrastructure, e.g., shore bases, etc.
- Transportation systems, including: gathering lines, terminals, tankers, icebreakers and pipelines.

The investment represents the cost to the Industry of bringing crude oil into production through the development of reservoirs in shallow water and deep water, and also includes developing onshore reserves.

Sales revenue generated by crude oil is targeted to commence before 1990, perhaps as early as 1986. Natural gas sales revenue may commence in 1990 to 1992. Figure 7.2-2 indicates accumulated revenue streams for the two levels of Beaufort development. Revenue is received initially from the sale of Beaufort crude oil to Canadian refiners for all production up to 1991-1992. Thereafter, Canadian demand is met and the balance of production could be exported. Thus, approximately 60% of total revenue derived in the technically achievable case is from foreign sales, representing income from foreign markets flowing into the Canadian economy.

Beaufort Region development will create 11,000 to 13,000 direct jobs by 1990. As illustrated in Figure 7.2-3, manpower requirements range from 17,000 to 24,000 by 2000. A high demand for temporary construction workers occurs if a major oil pipeline is to be constructed. In the mid 1980's, at the peak of pipeline construction, about 12,000 to 16,000 additional workers are required for pipeline construction. For the scenario where Arctic class tankers are utilized, an additional 2,000 to 3,000 shipyard workers would be employed in southern Canada over the 1986 to 2000 term to build the tankers. These are not included in Figure 7.2-3.

7.2.2 SOURCING IN CANADA

The capital investment for the project as reported in Figure 7.2-1 creates a demand for materials and services. The value of this direct industrial demand is

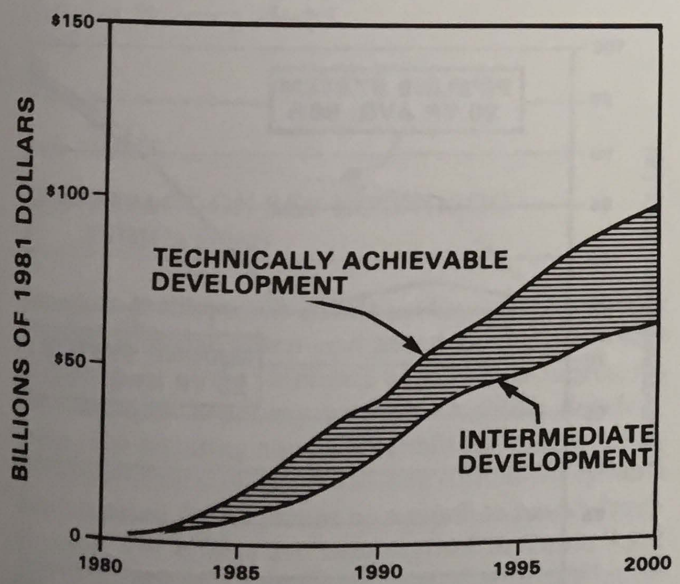


FIGURE 7.2-1 *Cumulative investment profiles (1981 dollars) for two levels of Beaufort development, the technically achievable case, and the intermediate case. This represents project expenditures for offshore, nearshore and onshore reserves, for oil and gas development, and for the two transportation systems.*

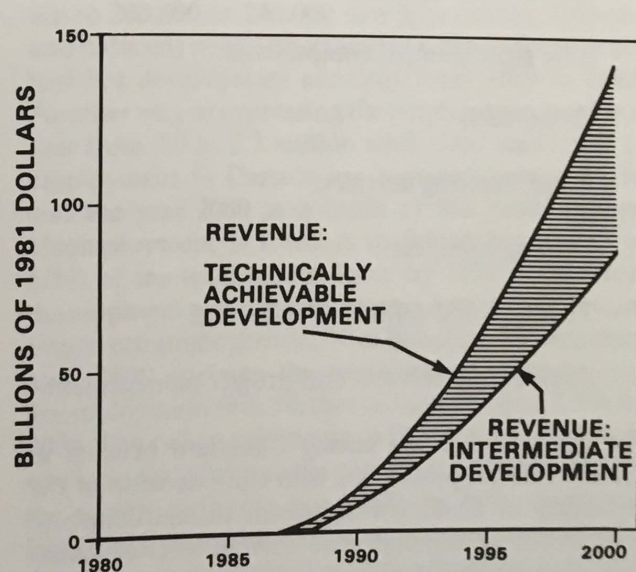


FIGURE 7.2-2 *Gross revenue profiles (1981 dollars) for two levels of Beaufort development, the technically achievable case, and the intermediate case. World crude oil prices are assumed to be $34.00 U.S. per barrel in 1982-83, growing thereafter at 1.5% to 2% in real terms above the U.S. inflation rate.*

estimated to range from $18 billion to $23 billion over the period from 1982 to 1990, and totalling $47 billion to $60 billion by 2000 (1981 dollars). The types of materials and services that would be purchased are as follows:

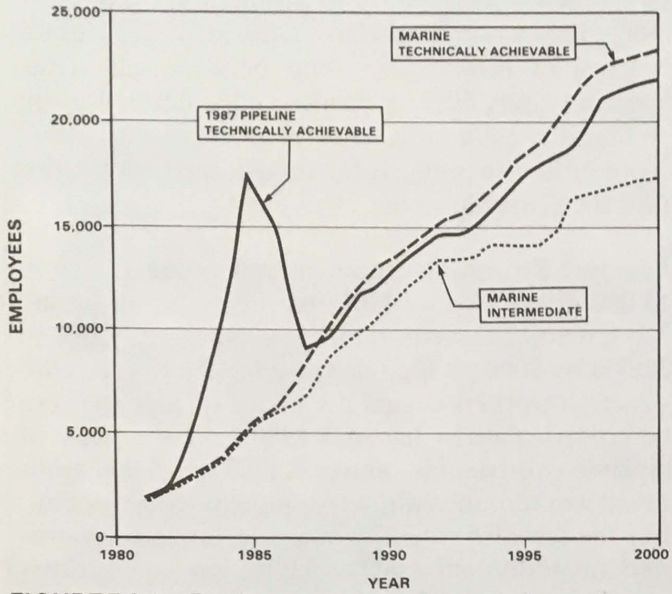


FIGURE 7.2-3 *Total manpower requirements for two levels of Beaufort development, the technically achievable case, and the intermediate case. Pipeline construction will create a peak demand, depending on the year of startup. The manpower profiles do not include the impact of the construction of a gas pipeline.*

- Drillships, drilling rigs, drilling platforms, caissons, conventional and larger dredges, icebreakers, tugs, supply boats barges, barge mounted production and storage facilities;

- Arctic Class tankers;

- Line pipe, pumps, compressors;

- Diesel fuel;

- Food, catering services;

- Drilling mud, etc.;

- Trucking and airline services; and

- Engineering services and project management.

The key to achieving strong Canadian benefits in Beaufort development lies with the extension of the capability of Canada's industrial infrastructure to meet Beaufort demand. The current level of Canadian content for Beaufort activities is in the 75% range.

It is anticipated that Canadian industry will expand in response to the long term sustained demand presented by Beaufort development. For this report it is assumed that the Canadian content of materials and services for Beaufort development will increase over time. An aggressive industrial expansion program could achieve an 85% overall Canadian content in materials and services by the year 2000. The analysis in this section assumes purchases made in Canada contain no foreign components. The major industrial elements of the program include:

- Expanded shipbuilding capacity in Canada;

- Canadian steel supply expanded to provide Arctic grade marine plate;

- A broader based shipyard suppliers' infrastructure capable of increased supply of diesel engines, marine electronics, compressors and pumps, general outfitting;

- Canadian supply of mild steel and large diameter pipe;

- Canadian supply of valves, pumps and turbines for pipeline systems;

- Expanded well casing, tubing supply; and

- Engineering and management services in Canada.

Figure 7.2-4 illustrates Canadian content profiles for the technically achievable level of development which represents an aggressive Canadian industrial expansion for the supply of materials and services.

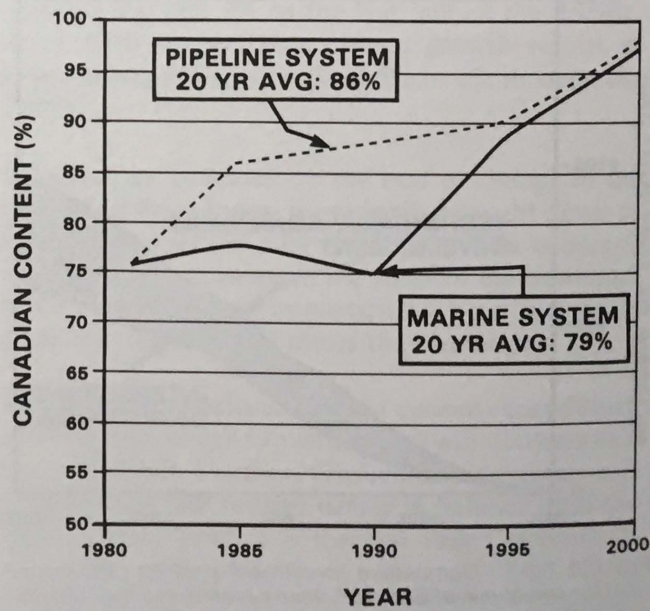


FIGURE 7.2-4 *Canadian content profiles for the technically achievable level of Beaufort development, for the two transportation modes. The forecast incorporates an aggressive Canadian industrial expansion program which includes a new international size shipyard to build 1 Arctic Class crude carrier per year. The balance of the Arctic Class ships are imported.*

For a pipeline based development scenario, overall Canadian content to the year 2000 for materials and services would approach 86%; for a total marine scenario it would be 79%. The reason for the lower content level for a marine scenario is that, because of capacity constraints, not all the Arctic crude carriers are built in Canada.

The aggressive expansion program includes increased shipbuilding capacity, primarily by adding a new "international-size" shipyard in Canada by 1986. The new shipyard would be designed to build some but not all of the Arctic crude carriers required in the marine system development cases. Although an average 1 to 1.6 crude carriers per year are required to 2000, the new shipyard would have a maximum capacity limited to 1 crude carrier per year in order to avoid the possibility of excess capacity in the future. Thus, several of the Arctic crude carriers, particularly in the early years of Beaufort development, may have to be sourced offshore. It is further assumed that the typical extensive supplier "core" will be established around a new shipyard, and that shipyard-grade steel is available in Canada. The Canadian content for tankers built in Canada could reach 85%.

For a pipeline transportation system, the Canadian shipbuilding capacity for oilfield development would still have to be expanded, but to a somewhat lower level than that for a marine case. This could still include a new shipyard in Canada in combination with the expansion of existing Canadian shipyards.

Canadian content profiles representing an aggressive industrial expansion program are incorporated in the Beaufort Planning Model.

7.2.3 IMPACT ON KEY ECONOMIC INDICATORS

Beaufort development effects on Canada's economy are very positive when compared to the economic performance of the reference case, which represents the Canadian economy without Beaufort development. The resulting national benefits as measured by the Informetrica Model, TIM, are similar for either a marine based development or a pipeline based development. The effects are summarized in Table 7.2-1 for the technically achievable case. For presentation purposes, this section will not differentiate between the two modes in describing the national macroeconomic results.

A Canadian economy stimulated by Beaufort development will experience real growth of 3% or more annually in Gross National Product (GNP), so that GNP exceeds the reference case levels in every year. To the end of the century this project would, in cumulative terms, add $210 billion to $220 billion (1981 dollars) to the economy. This cumulative figure is equivalent to one-third of projected GNP in 2000, or about two thirds of GNP in 1981.

The improvement in GNP is based initially on the strong direct investment effect. Once crude oil and natural gas production begins, project revenues rise and are distributed among suppliers, workers, governments, and project operators, further strengthening GNP. Personal real disposable income, after allowing for inflation effects, exceeds reference case levels in all years considered.

Government revenues are generated in royalties and taxes from increased crude oil production in Canada, and subsequently in taxes from a stronger, more active Canadian economy. Government account surpluses commence in the late 1980's, and continue thereafter. The cumulative impact on the Federal account could range from $118 billion to $122 billion (1981 dollars) during 1981 to 2000.

The current account balance is also in a strong surplus position throughout the forecast period. This measure of Canada's merchandise trade and financial services balance reflects the impact of replacing crude oil imports with Beaufort crude oil, and also indicates the potential benefits of exporting crude oil. For comparison, most Canadian economic forecasts (those which exclude Beaufort development) show a continuing and increasing current account deficit.

Up to 200,000 to 240,000 new jobs (direct, indirect, and induced) would be created in Canada from Beaufort Sea development annually from 1989 to 1995. Another way of expressing the employment benefit is that from 2.0 to 2.7 million additional man years of employment in Canada are required between now and the year 2000 as a result of this development. Unemployment is forecast to fall to between 5 to 5.5% of the total labour force by 1990 as Beaufort development and demand creates new jobs. The continued economic growth from Beaufort development after 1990 sustains the employment demand and unemployment falls further to between 4 to 4.5% by 2000. Thus when the impact of Beaufort development works its way through the economy in the late 1990's, the workforce could essentially be fully employed. For comparison, the Canadian economy described in the reference case which excludes Beaufort activity is forecast to expect unemployment levels of between 5.5% to 7% in the same time frame.

Significantly higher output in selected Canadian industries -manufacturing, transportation, services, financial - is required to support the Beaufort investment and production schedule.

TABLE 7.2-1

SUMMARY OF THE ECONOMIC IMPACT OF THE TECHNICALLY ACHIEVABLE LEVEL OF BEAUFORT DEVELOPMENT FOR BOTH THE MARINE AND PIPELINE TRANSPORTATION SYSTEMS. THE REFERENCE CASE IS THE CANADIAN ECONOMY WITHOUT BEAUFORT DEVELOPMENT

Indicator	*1981	1990		2000	
	Reference	Reference	With Beaufort	Reference	With Beaufort
Gross National Product (GNP) (1971$)	$134	$170	$5-$6 incr.	$255	$5-$6 incr.
Disposable Income (1971$)	$ 96	$120	$2-$3 incr.	$180	$4-$5 incr.
Business Investment (1971$)	$ 27	$ 38	$2-$4 incr.	$ 57	$2-$5 incr.
Government Surplus (Deficit)*	$(0.2)	$ (4)	$13-$17	$ 3	$50-$55
Current Account Balances**	$ 6.3	$ 15	$ 4-$10	$(25)	$50-$60
Consumer Price Index (1971=1.0)	2.4	4.8	4.7-5.2	9.7	9.5-10
Employment ('000 Jobs)	10,655	12,800	180-240 incr.	15,100	120-200 incr.
Unemployment Rate	7.4%	6.7%	5%-5.5%	5.4%	4%-4.5%
Exchange Rate ($Can/U.S.)	0.83	0.90	0.9-0.91	0.90	0.96-0.98

*Current Dollars, all Governments
**Current Dollars
Source: Informetrica's TIM Econometric Model, 1982.
Note: All Dollar Figures are Billions of Dollars

The manufacturing industry will respond to several major forces resulting from Beaufort development. These include the positive direct and indirect effects of the investment requirements, and additionally, the induced consumer demand for manufactured goods as incomes are increased relative to the reference case.

During the 1980's the effect is that manufacturing output is well above reference case levels. For the concentrated 3 to 4 year investment profile representing the construction of a pipeline, the manufacturing sector cannot meet all demands for the wide variety of industrial goods needed, and some imports may be necessary.

During the 1990's, direct Beaufort investment and corresponding manufacturing demand continue, but at lower levels than during the 1980's. During the same period further appreciation of the Canadian dollar results in increased import substitution. The net result is that manufacturing output is lower than reference case levels. The overall impact on manufacturing through the 1980's and 1990's is, however, positive.

Other sectors show continual gains in output. The transportation industry enjoys stronger output with Beaufort development as both the alternatives of pipeline or tanker operations add to the industry's output. As well, induced demands for transportation services to handle industrial goods will add to increased demands on that industry. The peak demand on the transportation sector occurs in the early 1990's. Services, including finance, insurance, real estate and trade, all reflect the effects of induced demand and show increased growth. These sectors respond in particular to increased consumer expenditures, and more generally to increased overall activity requiring service support. These major responses also occur in the early 1990's.

It should be noted, however, that the strong growth initiated by Beaufort development may contribute to certain economic difficulties. One area of importance relates to job skills and the available workforce. Generally speaking, when a workforce is at a high level of employment there will likely be skill shortages in some job categories. Shortages for Beaufort related direct jobs may occur in:

- engineering and technician professions;
- welders, insulators, electricians;
- marine officers and crew; and
- shipyard welders and pipefitters.

In many cases, training programs to upgrade skills will be required in lieu of immigration.

Another area of importance is the likely upward pressure that will be placed on the value of the Canadian dollar due to large offshore demand for Canadian currency if crude oil is exported. Such an appreciation could soften export and domestic demand for Canadian manufactured goods, but it would also reduce the forecast upward trend in consumer prices. If the dollar appreciates, inflation could be dampened by allowing imports to be more competitively priced, thus alleviating the pressure on Canadian industry. Some of the effects of an exchange rate appreciation on the manufacturing sector during the 1990's would be reduced by continued demand from Beaufort activities. However, the ultimate effects of Beaufort development on the Canadian economy will reflect policy decisions made by the Government that focus on a balance between exchange rate appreciation, desired strong manufacturing activity, and reasonable consumer price levels.

While the results of the macro-economic analysis reported above represent the impact of the technically achievable Beaufort development scenario, a lower level of development activity such as the intermediate Beaufort development scenario will still result in economic benefits to Canada.

As shown in Table 7.2-2 crude production could decrease by 40%, but the resultant level of investment would be a reduction in the order of 35%, and direct employment requirements would only be reduced by 25%.

GNP growth at this intermediate level of development is still judged to be strong, due to the large direct investment and employment requirements. Government surpluses will still exist at upwards of 60% of their previously reported levels. Job creation in Canada would be approximately 74% of full development impact, and Canada would still experience close to full employment levels. The current account balance is likely to remain in a surplus position, but would result in less pressure on an upward movement in the value of the Canadian dollar, maintaining strong consumer demand for domestic manufactured goods.

7.2.4 COMPARISON OF BENEFITS WITH COSTS

The purpose of a benefit-cost analysis is to determine whether a project usefully (or efficiently) employs society's resources. A benefit in this section is the value of the hydrocarbon production, as measured by its opportunity cost, i.e., the value that could be received for these resources in the world marketplace. Net benefits are the magnitude by which the benefits

TABLE 7.2-2

COMPARISON OF TWO LEVELS OF BEAUFORT DEVELOPMENT ACTIVITY REDUCING THROUGHPUT DOES NOT CAUSE INVESTMENT OR EMPLOYMENT TO FALL PROPORTIONATELY

	Date	Technically Achievable Development	Intermediate Development
Startup	1986:	1986	1986
Production Rate	1990:	445 MBD	260 MBD
	2000:	1,220 MBD	760 MBD
Cumulative Production to	2000:	4.1 B. Bbls.	2.4 B Bbls. (60%)
Fields Developed		12	7
Arctic Crude Carriers:	1990:	9	6
	2000:	25	16
Pipeline Diameter		42"	36"
Investment to	1990:	$37-$40 billion	$24-$27 billion (65%-67%)
(1981 Dollars) Total:		$101-$102 billion	$64-$67 billion (62%-66%)
Direct Employment:	2000:	23,000	17,000 (74%)

exceed the opportunity costs of the resources used to produce the hydrocarbons. If the present value of direct benefits exceeds direct costs, both discounted at a socially acceptable rate, then proceeding with the project is in the country's interest.

Direct benefits relate specifically to the project's revenue creation. For crude oil, the opportunity cost is defined to be the world crude oil price, and for natural gas the opportunity cost is 85% of the price for the heat-equivalent value of crude oil. Direct costs are the project's investment and operating costs associated with exploration, development, production and transportation. The market price for these goods and services in Canada and elsewhere is assumed to be a reasonable estimate of their opportunity costs.

Figure 7.2-5 indicates the extent that discounted benefits for Canada exceed the discounted costs. Results are presented for two levels of Beaufort development, the intermediate case and the technically achievable case. The project analysis shows that after consuming society's resources at their opportunity costs in Beaufort Sea hydrocarbon development, society would receive an additional net benefit of from $12 billion to $20 billion (1981 dollars) at a discount rate of 10% after allowing for inflation (the real social discount rate). Further analysis indicates that project costs could increase by 30%, or that production revenue could fall by 40% before the net benefit becomes zero.

These results suggest that for the range of Beaufort development considered the project is a net benefit to Canada.

It should be noted that this appraisal does not include the value of indirect benefits to Canada of Beaufort development. The appraisal also does not include the benefits of improved infrastructure in the north, extended communication links, upgraded social and health services, and training facilities. As well, social, environmental and infrastructure costs have not been included.

Incorporating the same benefits and costs approach above, the analysis was conducted for Canadian governments. Figure 7.2-6 indicates that the net benefits to governments will range from $9 billion to $16 billion (1981 dollars) at the same 10 percent real social discount rate used above. This range represents the impact of two Beaufort development levels; the intermediate case, and the technically achievable case. It is apparent that government's incentives in the form of the Petroleum Incentive Program (PIP) grants to encourage Beaufort development (here defined as costs) yield a net benefit in income that accrues from taxes and royalties.

There are other Government costs in addition to the PIP grants which have not been included, for example costs for education systems, transportation infrastructure, and social services. However, the net benefit to the Government from development is expected to be more than adequate to cover such costs.

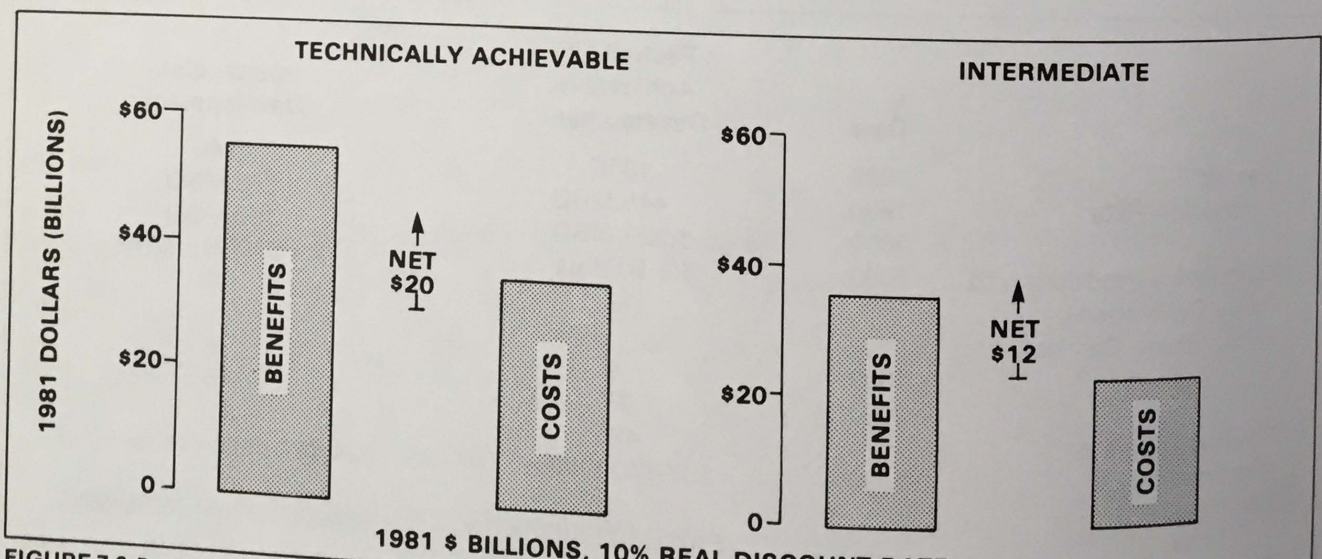


FIGURE 7.2-5 *Discounted benefits and costs to Canada for two levels of Beaufort development. Both yield net benefits at a 10% real social discount rate.*

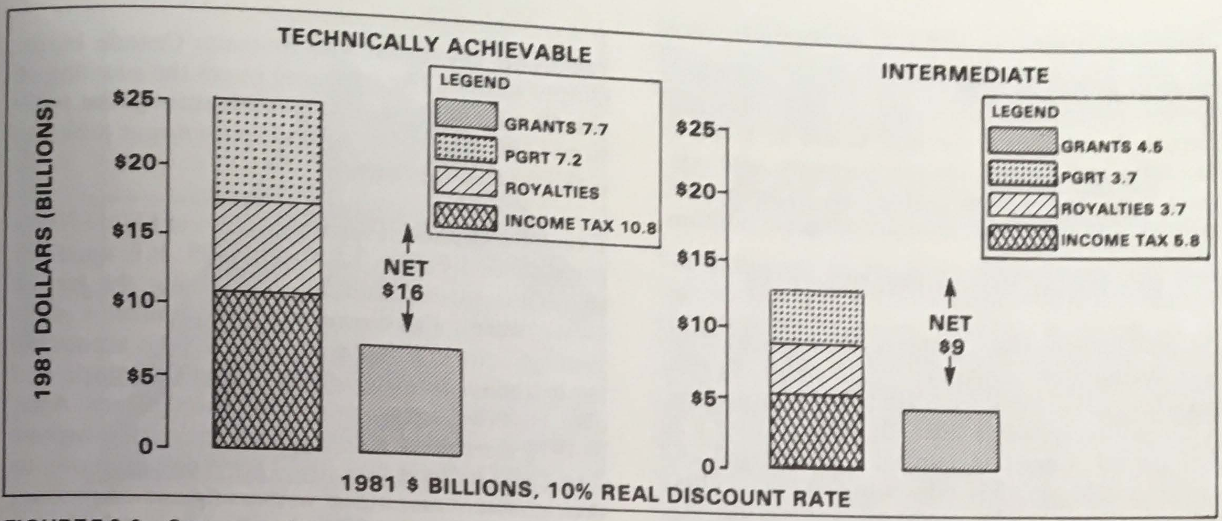


FIGURE 7.2-6 *Government account, discounted benefits and costs, for two levels of development. Net benefits occur in both cases.*

7.3 REGIONAL ECONOMIC BENEFITS

7.3.1 REGIONAL DISTRIBUTION

Beaufort development will affect all regions of Canada. The direct results in a regional sense are created by the degree of sourcing of materials and services from the regions, and by direct employment of people from each region. Since 80% of Beaufort personnel will commute on a 2 or 3 week schedule to their residences in all Canadian regions, these regions will benefit directly from employment income and associated provincial income taxes, property taxes, and consumer expenditures.

An aggressive Canadian industrial expansion program for increased supply of materials and services is outlined in Section 7.2.2 and results in an overall 85% Canadian content. This plan is translated in the Beaufort Planning Model to the detailed sourcing of 49 categories of materials and services, by year, over the forecast period. For direct Canadian purchases, the share of demand referred to in Section 7.2.2 will range between $18 billion and $23 billion of materials and services for Canadian industry by 1990, and $47 billion to $60 billion by 2000 (1981 dollars). Additional expenditures will be made for foreign materials and services.

The Canadian sourcing program contains anticipated purchases by region. The regional distribution is based on the existing industrial infrastructure and assumes that competition exists among suppliers. An example of the regional sourcing profile over time for a technically achievable Beaufort development scenario is provided in Figure 7.3-1. The profile represents 30 major manufacturing items. Here it can be seen that the Canadian content improves over time reflecting increased domestic supply capability.

The regional distribution of sourcing of materials and services is not the same for a pipeline based development as compared to marine. The overall sourcing percentages by regions in Canada are shown in Figure 7.3-2 for both transportation modes. Production development activity is common for both cases, requiring production islands dredged from sea-bottom material, and using barge-mounted drilling, production, and storage facilities. This aspect of development has a considerable marine-sourced requirement.

In the marine transportation mode, development focuses very strongly on an expanded marine shipbuilding industry, including a new international sized shipyard oriented to Canada's East Coast and Quebec. The Pipeline Case represents a moderate marine

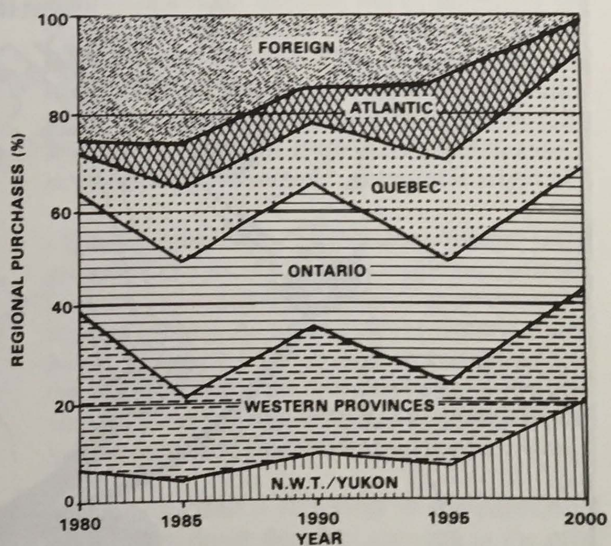


FIGURE 7.3-1 *Regional purchases of materials and supplies for the technically achievable level of Beaufort development. These represent the results of an assumed aggressive Canadian industrial expansion program in response to potential long term opportunities from Beaufort industrial demand.*

emphasis as well as large demand on an established pipeline construction framework focusing on central Canada. For instance, the pipe would be rolled in Hamilton and Regina, the two locations with adequate capacity for pipe of this size. In both cases however, steel makers are in an advantageous position.

7.3.2 REGIONAL SOURCING BENEFITS

Regional benefits from Beaufort development result from the purchase of materials and supplies. By 1990 this is forecast to range from $18 billion (marine case) to $23 billion (pipeline case). By 2000, or over a 20 year period, Canadian purchases of material and services could total $47 billion to $60 billion (1981 dollars). Figure 7.3-2 presents the regional distribution on a percentage basis. An example of the dollar value expenditure profile for Canadian regions is presented in Figure 7.3-3. These refer to purchases for the technically achievable development scenarios.

Another measure of regional benefit is the combined result of these direct purchases plus the "second-round" or indirect effects. This includes the effects of interprovincial trade required when products produced in one province necessitate inputs from another province. It also includes the first round of supplier purchases in the province.

The direct plus indirect effects of procurement in each region are calculated with Statistics Canada Input-Output tables . The appraisal traces the sourcing of the 49 material and service items through an additional 190 categories in the Input-Output tables to make up the total supply.

Examples of these benefits are shown in Figure 7.3-4a for 1990 and Figure 7.3-4b for 1995. It is apparent that Ontario, in addition to receiving the largest direct orders, also enjoys the largest indirect effect through inter-regional purchases. This is accounted for by the substantial industrial base in Ontario and also, by its linkages to other regions in Canada. Also, in 1990 the Prairie region enjoys the second-highest direct and indirect benefits. This is due primarily to the significant amount of well casing and oil production goods required in the Beaufort which are sourced from the established supply industry in Alberta. However, as noted above, linkages in the supply of this material to central Canada are also evident. Beaufort development will also enhance the economics of less advantaged regions in Canada. The scale of the development and its continuing large magnitude over time will dramatically benefit Yukon and the Northwest Territories. The close proximity of this region to the energy development scene will result in a direct growth of certain manufacturing and services industries.

A major part of the necessary expansion of Canada's

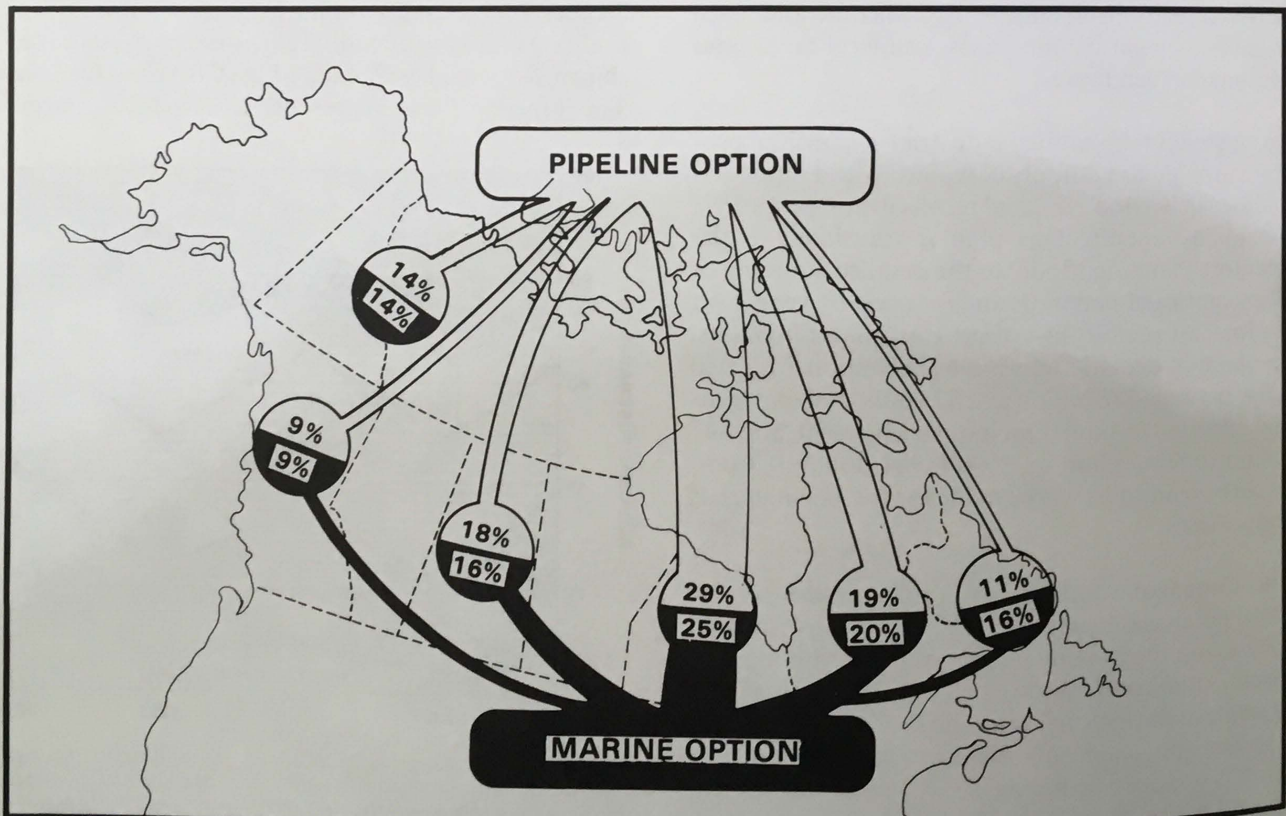


FIGURE 7.3-2 *Comparison of regional sourcing distribution for pipeline and marine transportation modes. Arctic tankers are built in a new shipyard in the Atlantic region. Major pipeline components are sourced in central and western Canada.*

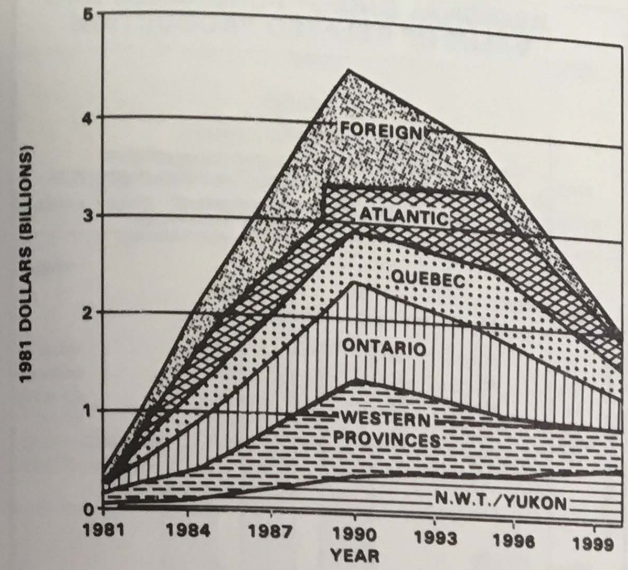


FIGURE 7.3-3 *Example of regional purchases of materials and services over a 20 year time frame for a technically achievable level of Beaufort development.*

shipbuilding industry to meet Beaufort demand will be in the Atlantic provinces. Shipbuilding creates large industrial supply centers in the immediate area of the shipyard. The benefits of increased demand for goods and services will become more pronounced in each of these regions over time as industrial bases mature. These effects are demonstrated in Figure 7.3-4a and 7.3-4b. Both the Atlantic provinces and the northern region enjoy a greater share of total output in 1995 than in 1990.

An example of the regional employment benefits of Beaufort development are presented in Figure 7.3-5 for 1990. Direct employment is indicated by place of residence and includes those working on Beaufort construction as well as those operating Beaufort facilities and employed on the transportation system. For 1990, the anticipated distribution suggests the largest direct employment will occur in Alberta, followed by Ontario. Indirect employment results from the provision of materials and services. Estimates of indirect employment for 1990 from the Input-Output tables indicate that Ontario benefits the most from Beaufort development, with indirect employment that is 10 times greater than its direct impact. New Brunswick, Nova Scotia and British Columbia play strong roles indirectly because of their existing or anticipated shipbuilding capacity. Quebec embodies both indirect roles ie: that of shipbuilding, and also as a manufacturer of other supplies. Quebec's employment impact supercedes Ontario's employment impact by 1995.

The employment effects multiply as income from the Beaufort flows through the economy. These induced employment effects are concentrated in Ontario and Quebec. For example, under the pipeline scenario in 1990, Ontario and Quebec contribute only 17% of the direct employment, but 48% of total employment. Thus, the strong existing industrial base and the established shipbuilding facilities increase the impacts on these central provinces.

7.3.3 IMPROVEMENTS IN TOTAL GROSS DOMESTIC PRODUCT BY REGION

The influence of Beaufort development on each region's Gross Domestic Product (GDP), a measure of a region's economic activity, is measured by Informetrica's Canadian macro-economic model (TIM) in conjunction with Statistics Canada's Input-Output tables. GDP gains, as measured here, represent the results of a region's production to meet Beaufort demand, plus the region's indirect production and further induced production due to Beaufort demand. These demands arise from direct sourcing in the provinces, and the demands induced by the wages of Beaufort employees resident in the region.

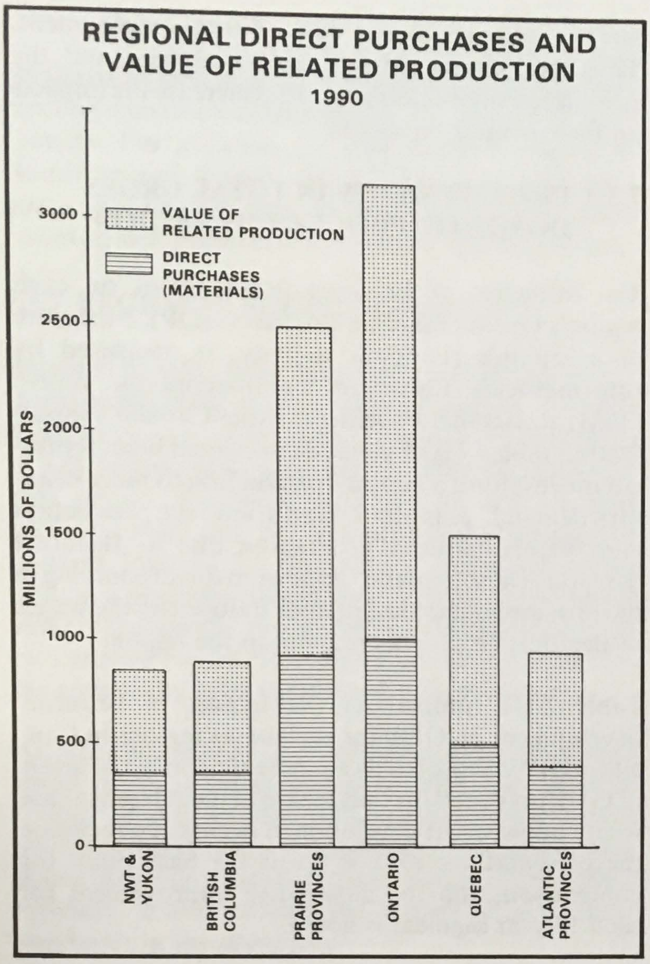
Table 7.3-1 summarizes the impact of Beaufort development on GDP for each of six regions in Canada. GDP is reported as an increase above the levels of GDP predicted for that region in the reference case where no Beaufort development occurs. To facilitate the presentation, 1981 is set as the base point for comparison, and the cumulative improvement for each 10 year segment is noted.

The benefits, as measured by improved regional GDP, can be summarized as follows:

- The Atlantic region enjoys the highest improvement in Gross Domestic Product. For example, the Atlantic region will experience an accumulated increase in GDP of 45 % to 51% to 1990 over what is forecast without Beaufort Sea development. By the year 2000 the additional cumulative growth increases from 104% to 125%. A major factor for this effect is the presence of large-scale shipbuilding in the region, plus the benefits of a more fully employed population. Even in the pipeline case, a large marine construction program is required.

- Quebec gains 32% - 34% in accumulated GDP growth by the year 2000. Direct regional materials sourcing and expanded shipbuilding are the major reasons for this. As in the case for Ontario noted below, Quebec's GDP is large in comparison to the value of direct Beaufort sourcing in the province. Quebec will also benefit as a regional supply base to expanded shipbuilding on the East Coast.

- Ontario's GDP is very large in comparison to the value of direct Beaufort sourcing in the province. However, the well established industrial linkages with other regions still result in a strong overall accumulated GDP growth of 34% to 38% by 2000. Accelerated shipbuilding in Quebec and



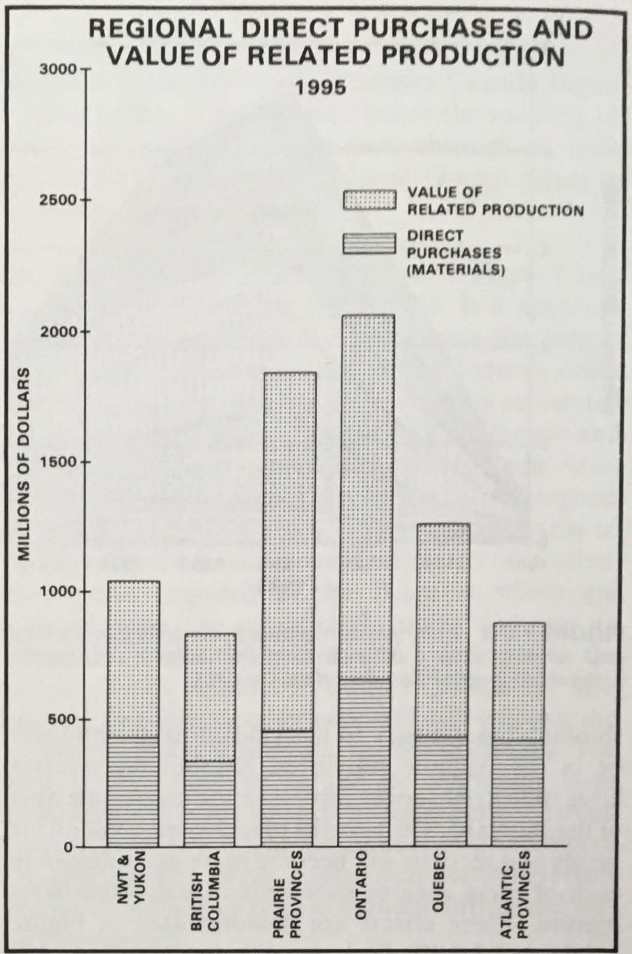


FIGURE 7.3-4a

FIGURE 7.3-4b

Examples of direct plus indirect industrial benefits of regional purchases (1981 dollars) for 1990 and 1995. Represented are the technically achievable cases for Beaufort development. Direct purchases create a second round of demand (indirect) for materials and services to supply the product purchased. The indirect demand can also occur between regions. Ontario, for example, could experience demand from Quebec in response to direct purchases in Quebec.

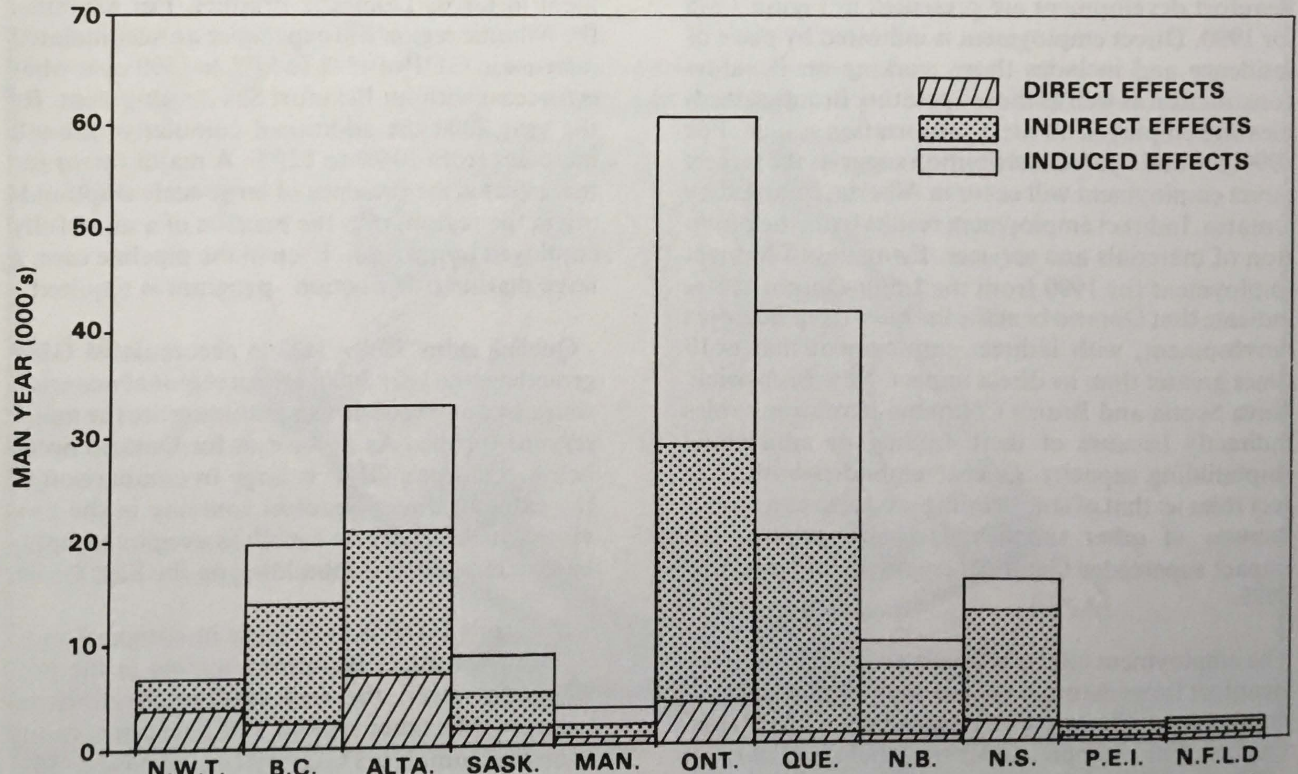


FIGURE 7.3-5 *An example in 1990 of the total employment benefits of a technically achievable level of Beaufort development. Direct employment represents jobs in the Beaufort Sea occupied by people resident in the regions. Indirect and induced employment effects reflect jobs created by sourcing in the region, or by jobs created to meet the growing consumer demand due to higher economic activity.*

TABLE 7.3-1

CUMULATIVE INCREASES TO REGIONAL GROSS DOMESTIC PRODUCT (GDP) RESULTING FROM BEAUFORT DEVELOPMENT FOR A MARINE BASED TECHNICALLY ACHIEVABLE DEVELOPMENT RATE

Region	1981	1990		2000	
		Marine	Pipeline	Marine	Pipeline
Atlantic	100	+51	+45	+125	+104
Quebec	100	+13	+14	+ 34	+ 32
Ontario	100	+13	+18	+ 34	+ 38
Prairies	100	+21	+24	+ 44	+ 48
British Columbia and Territories	100	+33	+37	+ 87	+ 89

in the Atlantic region will call on Ontario's industrial base for supplies. The demand for line pipe and related pipeline materials and equipment will also draw on central Canada's industrial base.

- For the Prairie region even today's strong GDP performance is still improved by Beaufort activity. The accumulated increase in GDP is 44% to 48% by 2000. The large ongoing demand for drilling equipment and supplies and for both Beaufort exploration and production wells provides the major stimulus for the economic impact on this region.

- In this macroeconomic analysis, British Columbia and the Northern Territories GDP's have been combined since reference GDP measurements for the Territories are not presently available. British Columbia's marine related industries will enjoy increased demand in response to Beaufort sourcing, and the provinces's GDP will improve. These regions' accumulated GDP will improve by 87% to 89% by 2000..

7.3.4 BENEFITS TO NORTHERN CANADA

The regional economic and employment impacts of Beaufort development will be pronounced in the north, and more specifically in the Beaufort Region and the Mackenzie Delta. Currently, the Territorial Governments continue to depend on Federal support at annual levels of approximately $4,800 to $7,200 per person. The rapidly growing young native population faces limited future opportunities for employment outside that presently offered through oil and gas exploration. The existing social and economic conditions for this region are reviewed in more detail in Volume 5.

Beaufort development will offer extensive employment opportunities for northerners. In both the technically achievable development case, and the intermediate development case the demand for employees residing in the north will in essence provide jobs for every person who has a desire to work in the Industry. For example, it is forecast that 3,000 to 4,000 Beaufort employees will reside in the north by 1990. This could increase to 5,000 to 7,000 Beaufort employees by the year 2000. The total number of jobs (direct, indirect and induced) created by Beaufort development will be greater. For example, new jobs would arise to staff retail stores, banks, garages, industrial and commercial businesses. Northern population growth will likely be concentrated in the Beaufort area and, to a large degree in proximity to Inuvik. The population of the Beaufort Region could range from 11,000 to 17,000 by 1990, and from 20,000 to 30,000 by 2000.

Revenue into the region can be identified in the form of salaries and wages received by Beaufort employees residing in the region. Direct salaries and wages are forecast to total $1.5 billion to $2.1 billion (1981 dollars) over the period to 2000. This income will be redistributed in the region for such items as housing, food and transportation. As the region's industrial base expands, more and more of the income received by employees will remain in the north. When the incomes of the indirect and induced jobs created are considered, the economic effect is much larger.

Sourcing of materials and services directly in the north is forecast to grow steadily through the forecast period, representing about 14% of the $47 billion to $60 billion in total to be expended in Canada for Beaufort development by the year 2000 (1981 dollars). Major regional demand could occur for drilling muds, barite, sand, gravel, fuel oil supply and distribution. Additional industrial and business opportunities can be identified generally for concrete manufacture and supply, prefab buildings, petroleum fuel supply and distribution, catering, banking, ship repair and maintenance, trucking, barging, air freight, parts and recreation.

The region as a whole would benefit from the establishment of the necessary support systems for Beaufort development. Some examples are:

- improvement of educational systems for northerners;

- improved and much expanded freight and personnel transportation networks (air, boat);

- better medical and social services;

- the creation of a generation of local entrepreneurs;

- a largely expanded retail and services sector.

The combined result is an improved self reliance in the north in social and in economic terms.

7.4 COMPANY PROGRAMS, GOVERNMENT POLICIES TO MAXIMIZE BENEFITS

The Federal Government presented a budget paper in November, 1981, entitled "Economic Development for Canada in the 1980's." The paper brings together the policies of the Government of Canada for national economic development, and states "this policy framework will guide the Government of Canada's actions in the coming years."

The development of natural resources is seen, by the Government of Canada, as a main stimulus for Canada's economic growth. Beaufort Sea development is a prime example. This has been demonstrated in the analyses through the Industry's Canadian Benefits Model, and through the macro-economic analyses conducted by Informetrica, as summarized in this chapter.

The following sections describe the contribution of Beaufort development to key objectives formulated by the Federal Government.

7.4.1 OIL SELF-SUFFICIENCY

Beaufort Region development and the Hibernia east coast development, both offshore plays, are the nearest term new major crude oil supply sources for Canada. Beaufort crude oil production in 1990 could make up the forecasted shortfall in Canadian crude oil needed to meet Canadian demand. With frontier production, Canada could become self sufficient in oil supply.

Beaufort Region development could be effective in placing new oil supply to the eastern region of Canada where imported oil is now used. Either a marine or a pipeline transportation system could deliver the oil directly to east coast refineries, both resulting in the backing out of imported crude oil.

Beaufort development is a significant energy project, as it represents at least 10% of the total value of all major projects reported by the Major Projects Task Force.

7.4.2 IMPROVING INDUSTRIAL ACTIVITY

Industry's objectives are aimed at maximizing Canadian economic and industrial benefits. In summary these objectives are:

1. Obtain goods and services on a fair and competitive basis, at the lowest cost, considering quality, safety, service, and delivery.

2. Support and encourage the development of Canadian industrial technology and production capacity by giving first opportunity to a broad range of domestic suppliers who are competitive, and whose products carry a high Canadian content.

3. Achieve substantial ongoing benefits both in employment and business to northerners and northern regions.

Beaufort activities historically have had a high Canadian content for goods and services. The operating phases of exploration have consistently experienced Canadian content in excess of 75% over the last 5 years. During the same period the magnitude of expenditures has increased 10 fold. The ongoing activity has encouraged the development of northern businesses and almost 200 northern businesses were involved in Beaufort related activities during 1981. This compares to less than 40 businesses 5 years ago.

Beaufort development provides the opportunity to broaden Canada's supply capability. Examples of this are:

- Canada's shipbuilding industry is identified as a critical supply deficient industry in relation to Beaufort demand. Present shipbuilding capacity must be increased to meet long term requirements. A proposal to double Canada's current shipbuilding capacity is before the Government. A new shipyard is envisioned as the most cost-effective way to add shipbuilding capacity for the construction of Arctic Class crude oil carriers. This will be an international size shipyard that could be located on either Canada's East or West Coast, to provide regional benefits where desired.

- The Davie Shipyard in Quebec is to expand to build Arctic vessels such as icebreakers, large dredges, and drilling systems. This optimizes the use of the existing labour pool inside the shipyard, and provides long term business opportunities for the established regional infrastructure around the shipyard.

- Other examples of supply gaps are found in pipeline construction requirements. Passive refrigeration units for the support of above-ground pipelines in a permafrost area could be built in Canada.

- Highly sensitive leak detection systems, and pipe throughput monitoring control systems could be supplied domestically.

Thus, Beaufort development provides a base demand on which the government can prepare long-term programs for expansion, and for upgrading productivity.

The long-term demand for a large range of domestic goods will allow existing industries to improve their efficiencies by utilizing slack capacity. Also, a long-term demand will permit industries to invest in modern production equipment and thus increase their future competitiveness.

7.4.3 EXPANDING TECHNOLOGICAL APPLICATIONS

Beaufort development offers ample opportunity for the development of new commercial technology in Canada. Many of the new technology applications will improve efficiency and cost effectiveness.

Technological applications which have already benefited Canada are:

- advanced ice-mechanics studies and applications;

- artificial island construction (Issungnak, Tarsiut, etc.);

- prototype icebreaker construction such as the KIGORIAK and ROBERT LEMEUR.

The Beaufort will cause new technology transfers to Canada in the areas of:

- sub-marine pipeline construction;

- Arctic pipeline design and construction; and

- highly sensitive "slow spill" pipeline sensor and monitoring systems.

The research and development associated with the introduction of new technology is demonstrated by the following examples:

- The ice regime in the offshore Beaufort Sea has necessitated the development of new Canadian technology to understand ice behaviour and forces, and to design facilities capable of operating in this ice regime. An international team of experts has been established in Canada to design and test production systems incorporating this new technology. This is an ongoing program. Systems are being tested and improved under operating conditions. The latest example is the Tarsiut caisson-retained test island built in 1981.

- Arctic marine operations require the development of innovative ice reconnaissance systems to determine ice movement, concentration, and thickness along the shipping route. This technology will complement existing Canadian electronics and satellite technology. Research and development has been initiated in Canada to advance this technology.

- Beaufort marine operations will require new technology to design and construct Arctic class crude carriers that can operate year-round in the northern region. Research and development to prepare a commercial cost-effective design has been underway for several years now. Prototype scaled down icebreakers have been built and tested. The latest ship, the KIGORIAK, has handled level ice up to 6 feet thick. A team of icebreaker naval architects has been assembled, and Canada is now acknowledged as a technological world leader in the icebreaker design field.

- A new shipyard would be established in Canada, incorporating the advanced shipbuilding technology and procedures, including Japanese quality control systems and European production systems. A Technical Assistance Agreement has been executed with Kawasaki Heavy Industries to transfer their technology in quality control systems to Canadian shipyards.

- The application of directionally controlled horizontal drilling for pipeline river crossings in environmental sensitive areas could be applied in northern Canada.

7.4.4 UPGRADING TRANSPORTATION SYSTEMS

The Mackenzie River system plays a key role in the Beaufort logistics of materials supply. Industry will not overload this system, or in any way impair delivery of supplies to local communities. As Beaufort development proceeds and the river system becomes fully loaded, the alternative ocean routes for supply to the Beaufort would be used.

Almost 80% of the substantial direct employment requirement in the Beaufort will be supplied by transporting people weekly from southern Canada. Air services to the north then will have to be significantly expanded and upgraded.

Aside from the technological and economic benefits of Beaufort activity, a year-round northern presence enhances Arctic sovereignty, and has strategic military implications for Canada. Additionally, large mineral reserves such as coal, uranium and iron ore will have better opportunity for development with

potential access to an appropriate year-round transportation system.

7.4.5. DEVELOPING HUMAN RESOURCES

All Beaufort activities offshore and onshore to date have included northern resident training and development programs to maximize employment opportunities. Industry policies for training northern residents for skilled and management positions in Beaufort development are reviewed in Volume 5, as are the policies regarding the training of northern businessmen.

Almost 25% of the total Beaufort peak employment of 1,265 people in 1981 were northerners. Total northern salaries and wages paid have increased 400% in the last 5 years.

There will be a demand for new skills emanating from Beaufort development. The Beaufort Planning Model outlines employment requirements by 30 job categories. Table 7.4-1 illustrates the broad range of skills required. Industry sponsored training programs will be expanded and broadened for northerners to provide the required skills. The supply of qualified people from all regions in Canada will require effective utilization of regional educational and skills upgrading programs. Additional jobs and skills would be required for expanded Canadian shipbuilding operations. Shipyard expansion proposals include special schools to upgrade skills levels to shipyard standards.

7.5 REFERENCES

Dome Petroleum Limited. 1982. Beaufort Sea Planning Model.

Informetrica Limited. 1982. The Informetrica Model (TIM).

TABLE 7.4-1

EMPLOYMENT CATEGORIES BEAUFORT REGION DEVELOPMENT

Geologist, Geophysicists	Radio, Pump, Mechanics	Seismic Crews
Engineers, Technicians	Drivers, Equipment Operators	Dredging Crews
Maintenance, Janitors	Welders	Log/Acid/Frac Crew
Production Operators	Insulators	Road Construction Crews
Supervisors, Administrators	Electricians	Drilling Workover Crews
Accounting, Clerical	Carpenters	General Labourers
Cooks, Helpers, Supply	Machinists, Millwrights	Security, Control
Aircraft Pilots, Crew	Pipeline Crews	Government Research, Environment
Marine Officers	Crane Operators	Unclassified, Others
Marine Crew	Concrete Masons	